July 21, 2026

**BY ELECTRONIC FILING**

The Honorable Debbie-Anne Reese, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

**Re**: **ISO New England Inc. and New England Power Pool, Docket No. EL25-106-000 Compliance Filing; Docket No. ER26-___-000**

**REQUEST FOR AN EFFECTIVE DATE OF OCTOBER 1, 2026, AND AN ORDER ON OR BEFORE SEPTEMBER 29, 2026**

Dear Secretary Reese:

Pursuant to Rule 1907 of the Federal Energy Regulatory Commission's (the "Commission") Rules of Practice and Procedure[1] and section 206 of the Federal Power Act ("Section 206"),[2] ISO New England Inc. (the "ISO" or "ISO-NE"), joined by the New England Power Pool ("NEPOOL") Participants Committee (together, the "Filing Parties"),[3] hereby submits this transmittal letter and proposed revisions to the ISO New England Transmission, Markets and Services Tariff ("Tariff")[4] in compliance with the January 22, 2026 Order Granting Complaint in Part and Denying in Part in Docket No. EL25-106-000.[5] The proposed revisions are collectively referred to as the "Compliance Proposal." The Compliance Proposal implements the Commission's directive to propose Tariff revisions to cap the Capacity Balancing Ratio at 1.0 and to make any conforming changes that ISO-NE finds necessary to effectuate the Balancing Ratio cap.[6]

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[1] 18 C.F.R. § 385.1907.

[2] 16 U.S.C. § 824e.

[3] Under New England's Regional Transmission Organization arrangements, the rights to make this filing of revisions to the Tariff under Rule 1907 of the Rules of Practice and Procedure of the Commission belong to the ISO. NEPOOL, which pursuant to the Participants Agreement provides the sole Participant Process for advisory voting on ISO matters, supported the revisions reflected in this filing, and, accordingly, joins this filing.

[4] Capitalized terms used but not otherwise defined in this filing have the meanings ascribed thereto in the Tariff, the Second Restated NEPOOL Agreement, and the Participants Agreement. Market Rule 1 is Section III of the Tariff.

[5] *New Eng. Power Generators Ass'n v. ISO New England Inc.*, 194 FERC ¶ 61,052 (2026) ("Order on Complaint").

[6] *See id.* at P 23.

The ISO respectfully requests that the proposed Tariff revisions take effect on October 1, 2026, and that the Commission act on this filing no later than September 29, 2026, which is more than 60 days from the date of this filing, in order to allow implementation of the Order on Complaint as soon as practicable.[7]

## I. DESCRIPTION OF THE FILING PARTIES AND COMMUNICATIONS

The ISO 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 ("TOA") 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 and the North American Electric Reliability Corporation.

The signatories to the New England Power Pool Agreement, which was first entered into in 1971, are referred to collectively as "NEPOOL." Currently, there are more than 560 signatories, which are referred to either as "Participants" or "members." They include all the electric utilities rendering or receiving services under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers (including owners of distributed generation and aggregators of such generation), developers, end users, and merchant transmission providers. Pursuant to revised governance provisions the Commission accepted,[8] the Participants act through the NEPOOL Participants Committee. Specifically, Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement authorize the Participants Committee to represent NEPOOL in proceedings before the Commission. Through the Commission-approved Participant Processes, NEPOOL is the vehicle through which all stakeholders with business interests in New England are able to provide informed input and advice to ISO-NE.

All correspondence and communications in this proceeding should be addressed to the undersigned for the ISO as follows:

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[7] As discussed in Section V of this transmittal letter, while the ISO is requesting an October 1, 2026 effective date for the proposed Tariff revisions, in accordance with the Order on Complaint, the ISO's Compliance Proposal would apply a July 25, 2025 refund effective date. *See id.* at P 61.

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

And to NEPOOL as follows:

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## II. BACKGROUND

### A. ISO New England's Pay for Performance Market Rules

While the Tariff revisions included with this Compliance Proposal are reasonably straightforward, certain features of the Pay for Performance ("PFP") market design, and the interaction between components of the design, add a degree of complexity to the proposal. To facilitate a clearer explanation of the Tariff changes, it is helpful to provide a brief overview of the PFP design, with an emphasis on certain relevant features.

ISO-NE's capacity market is a two-settlement market design consisting of Capacity Base Payments and Capacity Performance Payments.[10] Resources that sell

[9] 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.

[10] *See* Tariff §§ III.13.7.1, III.13.7.2, III.15.8.1, III.15.8.2; *see also* Order on Complaint at P 2; *ISO New England Inc.*, Revisions to Change the Capacity Performance Payment Rate to $3,500 per MWh, Docket No. ER26-3047, Transmittal Letter at 7–8 (filed June 30, 2026). The PFP market rules addressing Capacity Base Payments, Capacity Performance Payments, Monthly Capacity Payments and the stop-loss mechanism, and the allocation of Capacity Performance Payments are in Tariff Sections III.13.7.1, III.13.7.2, III.13.7.3, and III.13.7.4, respectively (for the Forward Capacity Market) and Tariff Sections III.15.8.1, III.15.8.2, III.15.8.3, and III.15.8.4, respectively (for the Annual Capacity Market). *See ISO New England Inc.*, 194 FERC ¶ 61,249, at P 1, 22 (2026) (accepting Tariff revisions to replace the Forward Capacity Market with a prompt capacity market with an Annual Capacity Auction).

capacity in a capacity auction receive Capacity Base Payments, which are determined by the auction clearing price and the MW quantity of capacity that each resource clears.[11]

Under the Pay for Performance market design, Capacity Performance Payments are determined by a resource's performance during Capacity Scarcity Conditions ("CSC"), and serve as the second settlement of the capacity market.[12] A resource's Capacity Performance Payment is equal to the product of its Capacity Performance Score ("CPS") (which represents a measure of the capacity the resource delivers as compared to its share of system obligation—i.e., its performance—during a Capacity Scarcity Condition), and the administratively set Performance Payment Rate, a dollar per MWh value set in the Tariff.[13] An individual resource's Capacity Performance Payment may be positive or negative,[14] and, under current rules, underperforming resources are charged and overperforming resources are paid at the Performance Payment Rate.[15] Ultimately, within the PFP design, Capacity Performance Payments are structured as financial transfers among underperforming and overperforming resources.[16]

*1. Capacity Balancing Ratio*

The Capacity Balancing Ratio (generally referred to herein as "Balancing Ratio" or "BR") is a measure of the total system needs during a Capacity Scarcity Condition (i.e., energy and reserves) relative to the aggregate Capacity Supply Obligations ("CSO") of all resources.[17] The Balancing Ratio is used to determine a resource's share of system obligation during Capacity Scarcity Conditions.[18] For each resource, whether or not it has a CSO, the ISO calculates a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource

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[11] Tariff §§ III.13.7.1 and III.15.8.1.

[12] *Id.* §§ III.13.7.2 and III.15.8.2. While the Pay for Performance market rules are the second capacity market settlement, the rules are structured to provide performance incentives to all resources, regardless of whether they have a Capacity Supply Obligation. However, while resources with an obligation to deliver capacity (i.e., with a Capacity Supply Obligation) can have either positive or negative Capacity Performance Payments, capacity that is *not* subject to a Capacity Supply Obligation cannot be subject to negative Capacity Performance Payments.

[13] *Id.* §§ III.13.7.2.6 and III.15.8.2.6.

[14] *Id.*

[15] *See ISO New England Inc.*, Filing to Implement Pay for Performance in the Forward Capacity Market, Docket No. ER14-1050-000, Transmittal Letter, at 45 ("PFP Transmittal Letter") (explaining that underperformance and overperformance are settled at the same price, the Performance Payment Rate); *see also* Order on Complaint at P 7 n.17.

[16] *See* PFP Transmittal Letter at 25–26.

[17] *See* Tariff §§ III.13.7.2.3, III.15.8.2.3.

[18] *Id.*; *see also* Order on Complaint at P 4.

is located.[19] The Capacity Performance Score component of the Capacity Performance Payment calculation is equal to the resource's Actual Capacity Provided ("ACP")[20] during the interval minus the product of the resource's CSO and the applicable Balancing Ratio.[21]

*2. Stop-Loss Mechanism and Allocation of Deficient or Excess Capacity Performance Payments*

Because Capacity Performance Payments can be negative, the PFP rules set a monthly stop-loss limit, which limits a capacity resource's net financial losses in each month of the Capacity Commitment Period, and an annual stop-loss limit, which limits a capacity resource's net financial losses over the entire annual Capacity Commitment Period.[22]

Additionally, to effectuate the financial transfers among underperforming and overperforming resources, the Pay for Performance design includes rules regarding the allocation of deficient or excess Capacity Performance Payments.[23] An excess may occur when, for example, the total amount of resource underperformance exceeds the total amount of resource overperformance.[24] A deficiency may occur when, for example, one or more resources reaches a stop-loss limit.[25] Under current rules, deficient or excess Capacity Performance Payments are allocated to resources with a Capacity Supply Obligation on a pro-rata (by CSO MW) basis.[26]

**B. Order on Complaint**

On January 22, 2026, the Commission issued an order granting in part and denying in part the New England Power Generators Association's ("NEPGA") July 25, 2025 Section 206 complaint against the ISO concerning certain components of ISO-NE's Pay for Performance market rules.[27] Specifically, the Commission directed ISO-NE to submit a compliance filing within 180 days of the date of the Order proposing Tariff revisions to cap the Balancing Ratio at 1.0 and to make any conforming changes that the

[19] Tariff §§ III.13.7.2.6, III.15.8.2.6.

[20] *Id.* §§ III.13.7.2.2, III.15.8.2.2.

[21] *Id.* §§ III.13.7.2.4, III.15.8.2.4.

[22] *Id.* §§ III.13.7.3.1, III.13.7.3.2, III.15.8.3.1, III.15.8.3.2; *see* Order on Complaint at P 6.

[23] *See* Tariff §§ III.13.7.4, III.15.8.4. The ISO refers to the deficient or excess Capacity Performance Payments as the "balancing fund" herein.

[24] *See* Order on Complaint at P 7 (citing PFP Transmittal Letter at 44–45).

[25] *See* Order on Complaint at P 8 (citing PFP Transmittal Letter at 45).

[26] Tariff §§ III.13.7.4, III.15.8.4.

[27] *See* Order on Complaint at P 1.

ISO finds necessary to effectuate the Balancing Ratio cap.[28] The Commission also established a July 25, 2025 refund effective date, finding, however, that, as of the date of the Order refunds were not warranted because the Balancing Ratio had not risen above 1.0 since the refund effective date.[29]

## III. TARIFF REVISIONS

In accordance with the Order on Complaint, the ISO's Compliance Proposal caps the Balancing Ratio at 1.0 and includes conforming changes necessary to effectuate the cap. The conforming changes: (1) modify the allocation of deficient or excess Capacity Performance Payments; (2) eliminate Capacity Performance Bilateral transactions; and (3) modify the definition of Average Balancing Ratio ("ABR") in the ISO New England Financial Assurance Policy ("FAP")[30] to account for the cap.

### A. Balancing Ratio Cap

Sections III.13.7.2.3 and III.15.8.2.3 of Market Rule 1[31] set forth the formula for calculating the Balancing Ratio. To implement the cap at 1.0, the ISO proposes to modify Sections III.13.7.2.3 and III.15.8.2.3 as follows (red text reflects new language):[32]

> For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:
>
> (Load + Reserve Requirement) / Total Capacity Supply Obligation
>
> *provided, however, that the Capacity Balancing Ratio shall not exceed a value of 1.0.*

[28] Order on Complaint at PP 23, 60.

[29] *Id.* at P 61.

[30] The FAP is Exhibit IA to Section I of the Tariff.

[31] The ISO's Compliance Proposal makes parallel changes in Sections III.13 and III.15 of the Tariff.

[32] The Tariff documents included in this filing reflect the proposed Tariff revisions to Sections III.13.7.2.5 and III.15.8.2.5 for the proposed change to the Performance Payment Rate, which were filed by the ISO on June 30, 2026 in *ISO New England Inc.*, Revisions to Change the Capacity Performance Payment Rate to $3,500 per MWh, Docket No. ER26-3047. The proposed Performance Payment Rate Tariff revisions are incorporated into the redline and clean Tariff documents as base text and are not shown as proposed revisions for the purpose of the present filing.

### B. Modifications to the Allocation of Deficient or Excess Capacity Performance Payments.

As noted above, the Pay for Performance design includes rules for allocating deficient or excess Capacity Performance Payments. The ISO's proposed revisions to these rules address two key considerations: (1) the potential balancing fund deficiency caused by capping the Balancing Ratio and the resulting effective Performance Payment Rate for overperformance, and (2) the separation of the allocation of stopped-losses from the allocation of other deficient or excess Capacity Performance Payments.

#### *1. Balancing Fund Deficiency and Effective Performance Payment Rate*

First, capping the Balancing Ratio at 1.0 creates a new source of a potential balancing fund deficiency. The Balancing Ratio cap can lead to a balancing fund deficiency because imposing the cap for a Capacity Scarcity Condition interval narrows the circumstances in which a resource will receive a negative Capacity Performance Score (because capping a Balancing Ratio that would have otherwise been greater than 1.0 will, in effect, reduce each capacity resource's share of the system's energy and reserve requirements for the interval).[33] Therefore, some negative Capacity Performance Payments that would have been charged under an uncapped Balancing Ratio will not be charged. Ultimately, the total resource overperformance could exceed total resource underperformance, creating a deficiency in charges accrued relative to payments owed.[34]

Under the Compliance Proposal, the ISO's proposed conforming Tariff changes allocate any such deficiency to overperforming resources, proportionally by positive Capacity Performance Score, thereby reducing payments for overperformance.[35] This approach results in an effective payment rate for resource overperformance during a

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[33] As noted above, CPS = ACP – (CSO × BR), so, all else equal, reductions to the Balancing Ratio increase a resource's Capacity Performance Score (or have no impact on the resource's Capacity Performance Score if the resource's CSO is 0).

[34] *See* Order on Complaint at P 43 ("The [Internal Market Monitor for ISO-NE ("IMM")] contends that ISO-NE and its stakeholders will have to consider how to adjust the credit and allocation side of the Pay for Performance design to reflect the resulting shortfall in revenue collection due to the capped Balancing Ratio. The IMM argues that capping the Balancing Ratio at 1.0 will result in an under-collection of funds to resources for providing energy and reserves during a scarcity event.")(citing *New Eng. Power Generators Ass'n v. ISO New England Inc.*, Docket No. EL25-106-000, Comments of the Internal Market Monitor for ISO New England, at 1–3 (filed September 4, 2025).

[35] As explained in Section II.A.2, under current rules, Capacity Performance Payment deficiencies are allocated to capacity resources on a pro-rata by CSO MW basis. Mathematically, the ISO could continue this approach and allocate deficiencies caused by capping the Balancing Ratio to capacity resources on a CSO MW basis. However, such an allocation would result in the same charges to capacity resources as an uncapped Balancing Ratio, thereby negating the effect of the Balancing Ratio cap.

Capacity Scarcity Condition that may be lower than the Tariff-defined Performance Payment Rate that underperforming resources are charged.

To illustrate how allocating a deficiency caused by capping the Balancing Ratio would reduce payments for overperformance, consider the following scenario:

- Total CSO is 30,000 MW and there is a 1-hour Capacity Scarcity Condition, with a Load + Reserve Requirement of 31,500 MW, resulting in a Balancing Ratio of 1.05 (31,500/30,000).
- CSO resources contributed 26,000 MWh during the CSC. With an uncapped Balancing Ratio of 1.05, $51,353,500 in charges would accrue ([31,500 – 26,000] × $9,337). With a Balancing Ratio capped at 1.0, $37,348,000 in charges accrue ([30,000 – 26,000] × $9,337).[36]
- Overperforming resources contributed 5,000 MWh and would earn $46,685,000 in credits at the full Performance Payment Rate.
- With an uncapped Balancing Ratio, the charges that accrue from underperforming resources would be sufficient to pay overperforming resources at the Performance Payment Rate of $9,337 ($51,353,500/5,000) and would result in an excess in the balancing fund.
- With a Balancing Ratio capped at 1.0, the charges that accrue from underperforming resources would result in a deficiency and an effective Performance Payment Rate of $7,470/MWh ($37,348,000/5,000) to overperforming resources.[37]

Thus, in the example, capping the Balancing Ratio causes a deficiency in which the charges that accrue from underperforming resources are insufficient to pay overperforming resources at the full Performance Payment Rate. Allocating that deficiency to overperforming resources (proportionally by positive Capacity Performance Score) produces an effective Performance Payment Rate for overperformance that is less than the Performance Payment Rate charged for underperformance.

Additionally, while not addressed in this simplified scenario, the amount of resource overperformance and underperformance, as well as the Balancing Ratio, can vary by five-minute interval. This means that the amount of any deficiency, and the resulting $/MWh payment rate calculation, could vary by interval.[38]

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[36] Tariff §§ III.13.7.2.5, III.15.8.2.5. As noted above, the ISO has filed with the Commission a proposal to change the Performance Payment Rate to $3,500 per MWh.

[37] The ISO also discussed examples of an effective Performance Payment Rate in its Answer to NEPGA's Complaint. *See New Eng. Power Generators Ass'n v. ISO New England Inc.*, Docket No. EL25-106-000, Answer to Complaint of ISO New England Inc. ("ISO Answer to Complaint"), at 26–28 (filed August 21, 2025).

[38] *See id.* at 34.

Taking into account these dynamics, and consistent with the current monthly allocation for deficient or excess Capacity Performance Payments,[39] the ISO proposes to allocate any deficiency due to the application of the Balancing Ratio cap on a monthly basis. This approach results in a single effective Performance Payment Rate for overperformance for a month and ensures equal payments for equal performance within a month. Applying a similar approach, the ISO also proposes to pool Capacity Performance Payments into a single balancing fund for the month, regardless of the occurrence of zonal Capacity Scarcity Conditions.[40] Together with the monthly allocation, this approach retains the single effective Performance Payment Rate across the month.

*2. Independent Stop-Loss Allocation*

Second, to account for the potential for the Balancing Ratio cap to cause a balancing fund deficiency and to ensure that any deficiencies due to stopped-losses continue to be allocated to resources with Capacity Supply Obligations,[41] the proposed Tariff revisions separate the allocation of stopped-losses from the allocation of other deficient or excess Capacity Performance Payments.

*3. Tariff Sections III.13.7.4 and III.15.8.4*

The proposed Tariff revisions discussed above are reflected in the text of Tariff Sections III.13.7.4 and III.15.8.4. Specifically:

- Proposed revisions to the introductory paragraph and subsections (a) and (b) implement a single balancing fund for the month, regardless of the occurrence of zonal Capacity Scarcity Conditions.[42]
- Proposed revisions to subsection (a) allocate deficient Capacity Performance Payments to overperforming resources rather than resources with a Capacity Supply Obligation.[43]
- Proposed revisions to subsections (a) and (b), and new subsection (c) separate the allocation of stopped-losses from the allocation of deficient or excess Capacity Performance Payments. Subsection (c) also continues to

[39] *See* Tariff §§ III.13.7.4, III.15.7.4.

[40] Specifically, deficient Capacity Performance Payments are allocated proportionally by share of positive Capacity Performance Scores across all Capacity Scarcity Condition intervals and Capacity Zones subject to a Capacity Scarcity Condition.

[41] *See* Order on Complaint at PP 82–83 (finding that "it is reasonable for capacity resources to bear the costs [of deficiencies due to the stop-loss mechanism] because all capacity resources benefit from the stop-loss mechanism").

[42] The proposed Tariff revisions also include changes for language consistency.

[43] In subsection (b), the allocation of excess Capacity Performance Payments is unchanged, and excess Capacity Performance Payments continue to be allocated to capacity resources pro-rata on a CSO MW basis.

allocate stopped-losses to capacity resources on a pro-rata by CSO MW basis and explains that, if the allocation of any deficiency, including a deficiency due to the allocation of stopped-losses, causes a resource to reach a stop-loss limit, then the stop-loss limit will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in subsection (c).

### C. Capacity Performance Bilaterals

The current Pay for Performance rules permit Market Participants to enter into Capacity Performance Bilaterals and trade their performance bilaterally.[44] Under this construct, if a resource has a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five-minute interval so long as both resources were subject to the same Capacity Scarcity Condition.[45] Such a transaction has the effect of modifying the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Conditions subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments.[46]

As discussed above, under the proposed Tariff revisions, the effective Performance Payment Rate for resource overperformance may be lower than the Performance Payment Rate charged for underperformance. This asymmetry could allow a Market Participant to use a positive Capacity Performance Score with a lower effective payment value to trade away an equivalent negative Capacity Performance Score that would be subject to a higher charge rate, thus avoiding the full charge that the participant would have otherwise paid.[47] Such a transaction would lead to a "money-for-nothing" problem and, by reducing the funds available, could further reduce the effective payment rate for other overperforming resources.

To address these potential inefficiencies, the ISO is proposing to eliminate Capacity Performance Bilaterals.[48] To effect this change, the ISO is proposing to delete the definition of Capacity Performance Bilateral from Tariff Section I.2.2 and to delete Tariff Sections III.13.5.3 and III.15.6.3 in their entirety. The ISO is also proposing to

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[44] *See* Tariff §§ III.13.5, III.15.6; PFP Transmittal Letter at 51.

[45] Tariff §§ III.13.5.3.1, III.15.6.3.1; PFP Transmittal Letter at 51.

[46] Tariff §§ III.13.5.3.3, III.15.6.3.3; PFP Transmittal Letter at 51. Including Capacity Performance Bilateral transactions in the Pay for Performance rules provided a tool for Market Participants to manage potential non-performance risk. However, the tool has been utilized minimally since Pay for Performance was established.

[47] *See* ISO Answer to Complaint at 33 (discussing the impact of the introduction of different effective Performance Payment Rates on Capacity Performance Bilaterals).

[48] *See id.* at 34 (identifying the potential need to discontinue the existing Capacity Performance Bilateral rules).

delete references to Capacity Performance Bilaterals from Tariff Sections III.1.1, III.1.4.2, III.13.5, III.15.6, and from the Table of Contents of Market Rule 1.

### D. Modification to the Definition of Average Balancing Ratio

Under the Financial Assurance Policy, the Average Balancing Ratio ("ABR") is a component of the Forward Capacity Market ("FCM") Delivery Financial Assurance formula.[49] The ABR is the duration-weighted average of all of the system-wide Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months (summer, winter, shoulder) in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period.[50] In the FCM Delivery Financial Assurance formula, a resource's capacity weighted average performance is measured against the ABR, which represents a resource's share of system obligation. That calculation is one component used in determining a Market Participant's FCM Delivery Financial Assurance requirements.[51]

Because the ABR calculation utilizes an historic "look back" at prior system-wide Balancing Ratios, it is necessary to specify whether, in performing that look back, the ISO will apply the Balancing Ratio cap to historic values associated with Capacity Scarcity Conditions that took place before the Balancing Ratio cap went into effect. The ISO proposes to utilize the capped historic Balancing Ratio values, because this would allow the FCM Delivery Financial Assurance to more accurately capture the necessary collateral for the updated Pay for Performance rules (i.e., in which capping applies). To incorporate the cap of 1.0 into the historic Balancing Ratio values, the ISO proposes to modify the definition of ABR as follows (red text reflects new language):

> ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. *For the purpose of calculating the ABR, all Capacity*

[49] FAP, Section VII.A.

[50] *Id*. Section VII.A.1.

[51] *See ISO New England Inc.*, Revisions to Update Certain Definitions in the FCM Delivery Financial Assurance Formula, Docket No. ER25-2403, Transmittal Letter, at 5 (filed June 2, 2025) ("The ABR and CWAP [capacity weighted average performance] portion of the formula helps collateralize against the potential risk that a participant will default on payment obligations arising from negative capacity payments associated with a CSO after non-performance or underperformance of its resources during a Capacity Scarcity Condition. As a result, that portion of the formula uses historical performance data relative to the amount of system-wide reserves needed to avoid a Capacity Scarcity Condition.").

*Balancing Ratios, including Capacity Balancing Ratios for Capacity Scarcity Conditions that occurred in past Capacity Commitment Periods or in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, shall be calculated utilizing the Capacity Balancing Ratio formula that is currently effective, as described in Section III.13.7.2.3 or Section III.15.8.2.3 of Market Rule 1.* Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60.

## IV. STAKEHOLDER ENGAGEMENT AND THE NEPOOL PARTICIPANT PROCESS

Over the course of three meetings of the NEPOOL Markets Committee, starting in March 2026, the ISO discussed its Compliance Proposal to implement the capped Balancing Ratio with regional stakeholders. At its May 12–14, 2026 meeting, based on a show of hands vote, the NEPOOL Markets Committee voted unanimously, with abstentions noted, to recommend a motion that the NEPOOL Participants Committee support the proposal.[52]

Over the course of two meetings of the NEPOOL Budget and Finance Subcommittee,[53] starting in April 2026, the ISO discussed the revision to the ABR definition in the FAP. No subcommittee member present at the meeting objected to or expressed concerns with the revision.

At its June 16–18, 2026 meeting, the NEPOOL Participants Committee considered the Markets Committee-recommended Tariff revisions to implement the capped Balancing Ratio. Based on a show of hands vote, the Participants Committee unanimously supported the proposal, with abstentions noted.[54]

## V. EFFECTIVE DATE

The ISO is requesting an October 1, 2026 effective date to allow time for the ISO to implement the new market rules. Additionally, the Order on Complaint established a

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[52] There were two abstentions, one from a member of the Generator Sector and another from a member of the End User Sector.

[53] The Budget and Finance Subcommittee is a non-voting subcommittee that provides input and advice to the ISO and the NEPOOL Participants Committee concerning changes to Financial Assurance Policy, among other things.

[54] The following members abstained: FirstLight Power Management LLC (Generation Sector); H.Q. Energy Services (U.S.) Inc. (Alternative Resources Sector); and Mr. Jon Lamson (End User Sector).

July 25, 2025 refund effective date.[55] Noting that the Balancing Ratio had not risen above 1.0 since that date, the Commission found that, as of January 22, 2026, refunds were not warranted.[56] As of July 20, 2026, the Balancing Ratio has not risen above 1.0. However, in accordance with the Commission's Order, if the Balancing Ratio rises above 1.0 before the Tariff revisions to implement the Balancing Ratio cap are in effect, the ISO will apply any required adjustments to the allocation of Capacity Performance Payments in accordance with the revised Tariff through the ISO's Data Reconciliation Process for the affected settlement month(s).

## VI. DOCUMENTS SUBMITTED IN THIS FILING

This filing includes the following materials:

- This transmittal letter;
- Redlined Tariff sections effective October 1, 2026; and
- Clean Tariff sections effective October 1, 2026.

[55] Order on Complaint at P 61.

[56] *Id.*

## VII. CONCLUSION

For the reasons set forth above, the Filing Parties respectfully request that the Commission accept the Tariff revisions filed herein, effective October 1, 2026, as fully satisfying the Commission's directives in the January 22, 2026 Order on Complaint.

Respectfully submitted,

**ISO NEW ENGLAND INC.**

By: */s/ Kelly Caiazzo*

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**NEW ENGLAND POWER POOL PARTICIPANTS COMMITTEE**

By: */s/ Rosendo Garza, Jr.*

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**CERTIFICATE OF SERVICE**

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

Dated at Holyoke, Massachusetts this 21st day of July, 2026.

*/s/ Julie Horgan*
Julie Horgan
eTariff Coordinator
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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:

**Above-Threshold Offer Segment** is the total MW quantity of a Capacity Offer that is priced above the Capacity Offer Price Threshold, whether such MW quantity is delimited by only one price-quantity pair or multiple price-quantity pairs submitted as part of the Capacity Offer pursuant to Section III.15.4.1.

**Active Demand Capacity Resource** is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward or Annual Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 or Section III.15 of Market Rule 1.

**Actual Capacity Provided** is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 or Section III.15.8.2.2 of Market Rule 1.

**Actual Load** is the consumption at the Retail Delivery Point for the hour.

**Additional Resource Blackstart O&M Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Additional Resource Specified-Term Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Additional Resource Standard Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Administrative Costs** are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

**Administrative Export De-List Bid** is a bid 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.

**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.

**Advisory Qualified Capacity Values** are the advisory summer and winter Qualified Capacity values, calculated pursuant to Section III.15.2.5.

**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.

**Allowable Capacity Offer Price** is a price determined by the Internal Market Monitor as part of its review of Proposed Capacity Offers pursuant to Section III.A.22.2.3.

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

**Alternative Technology Regulation Resource (ATRR)** is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

**Ancillary Services** are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

**Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount** are defined in Section IV.B.2.2 of the Tariff.

**Annual Capacity Auction (ACA)** is the Annual Capacity Market auction process carried out pursuant to Section III.15.4 of Market Rule 1.

**Annual Capacity Auction Cleared Export Transaction** is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

**Annual Capacity Auction Offer Window** is the period described in the Capacity Auction Calendar during which Capacity Offers must be submitted for an Annual Capacity Auction.

**Annual Capacity Market** is the annual market for procuring capacity in the New England Control Area, as set forth in Section III.15 of Market Rule 1.

**Annual Qualified Capacity** is the Qualified Capacity calculated pursuant to Section III.15.3 that is used in an Annual Capacity Auction.

**Annual Transmission Revenue Requirements** are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

**Annual Reconfiguration Transaction** is a bilateral transaction associated with the Forward Capacity Market that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

**Applicants**, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

**Application** is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

**Asset** is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, a Distributed Energy Resource participating as part of a Demand Response Distributed Energy Resource Aggregation, a Settlement Only Distributed Energy Resource Aggregation, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

**Asset Registration Process** is the ISO business process for registering an Asset.

**Asset Related Demand** is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration; (2) a Storage DARD with a consumption capability of at least 0.1 MW; or (3) one or more storage facilities that are not Electric Storage Facilities with an aggregate consumption capability of at least 1 MW.

**Asset Related Demand Bid Block-Hours** are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

**Asset-Specific Going Forward Costs** are the net costs of an asset that is part of a Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Generating Capacity Resources as described in Section III.A.22 (for an asset associated with a Capacity Offer price subject to Internal Market Monitor review) or Section III.A.24 (for an asset submitting a Deactivation Notification).

**Assigned Meter Reader** reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

**Auction Revenue Right (ARR)** is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

**Auction Revenue Right Allocation (ARR Allocation)** is defined in Section 1 of Appendix C of Market Rule 1.

**Auction Revenue Right Holder (ARR Holder)** is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

**Authorized Commission** is defined in Section 3.3 of the ISO New England Information Policy.

**Authorized Person** is defined in Section 3.3 of the ISO New England Information Policy.

**Automatic Response Rate** is the response rate, in MW/Minute, at which a Market Participant is willing to have a Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

**Available Energy** is a value that reflects the MWhs of energy available from an Electric Storage Facility for economic dispatch.

**Available Storage** is a value that reflects the MWhs of unused storage available from an Electric Storage Facility for economic dispatch of consumption.

**Average Hourly Load Reduction** is either: (i) the sum of the On-Peak Demand Capacity Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Capacity Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.15.2.1.1.2.1 or Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

**Average Hourly Output** is either: (i) the sum of the On-Peak Demand Capacity Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Capacity Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 or Section III.15.2.1.1.2.1 of Market Rule 1 and the ISO New England Manuals.

**Backstop Transmission Solution** is a solution proposed: (i) to address a reliability 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.

**Benchmark Scenario** is an Economic Study reference scenario that is described in Section 17.2(a) of Attachment K to the OATT.

**Bilateral Contract (BC)** is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

**Bilateral Contract Block-Hours** are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

**Binary Storage DARD** is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Binary Storage Facility** is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Blackstart Capability Test** is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

**Blackstart Capital Payment** is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

**Blackstart Equipment** is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

**Blackstart O&M Payment** is the annual Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

**Blackstart Owner** is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

**Blackstart Service** is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

**Blackstart Service Commitment** is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

**Blackstart Service Minimum Criteria** are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

**Blackstart Standard Rate Payment** is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

**Blackstart Station** is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

**Blackstart Station-specific Rate Payment** is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

**Blackstart Station-specific Rate Capital Payment** is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the

provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

**Block** is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day); and (8) with respect to Day-Ahead Ancillary Services Offers administered by the ISO, a quantity with a related price for Day-Ahead Ancillary Services (Day-Ahead Ancillary Services Offers may contain multiple prices for each hour).

**Block-Hours** are the number of Blocks administered for a particular hour.

**Budget and Finance Subcommittee** is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

**Business Day** is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

**Cancelled Start NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Capability Demonstration Year** is the one year period from September 1 through August 31.

**Capacity Acquiring Resource** is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 or Section III.15.6.1, or; (2) a reconfiguration auction, as described in Section III.13.4 or Section III.15.5.

**Capacity Auction Calendar** is a calendar published on the ISO's website, as described in Section III.15, detailing dates and deadlines associated with Annual Capacity Market participation, Monthly Reconfiguration Auction participation, and monthly Capacity Supply Obligation Bilateral transactions.

**Capacity Auction Offer Price Cap** is determined pursuant to Section III.15.1.2.1 of Market Rule 1 prior to the Annual Capacity Auction for each Capacity Commitment Period and is the highest price at which capacity may be offered into the Annual Capacity Auction, unless otherwise expressly allowed by the Tariff.

**Capacity Balancing Ratio** is a ratio used in calculating the Capacity Performance Payment in the Capacity Market, as described in Section III.13.7.2.3 or III.15.8.2.3 of Market Rule 1.

**Capacity Base Payment** is the portion of revenue received in the Forward Capacity Market or Annual Capacity Market as described in Section III.13.7.1 or Section III.15.8.1 of Market Rule 1.

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

**Capacity Clearing Price** is the clearing price in 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 or resulting from the Annual Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.15.4.2.

**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 and Annual 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 Demonstration Deadline** is a monthly deadline described in the Capacity Auction Calendar for completion of the capacity demonstration requirement set forth in Section III.15.2.6 prior to participation in the Annual Capacity Auction, a Monthly Reconfiguration Auction, or a Capacity Supply Obligation Bilateral transaction.

**Capacity Export Through Import Constrained Zone Transaction** is defined in Section III.1.10.7(f)(i) of Market Rule 1.

**Capacity Load Obligation** is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 or Section III.15.8.5.2 of Market Rule 1.

**Capacity Load Obligation Acquiring Participant** is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 or Section III.15.6.2 of Market Rule 1.

**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 or Section III.15.6 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 or Section III.15.6.2 of Market Rule 1.

**Capacity Market** is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1, or the annual market for procuring capacity in the New England Control Area, as described in Section III.15 of Market Rule 1.

**Capacity Market Commercial Operation** is defined in Section III.15.2.6 of Market Rule 1.

**Capacity Market Deactivation** is the permanent removal of a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource from the Capacity Market, or the permanent reduction in Capacity Network Import Capability of an External Elective Transmission Upgrade, as described in Section II.I of the OATT.

**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 Network Resource (CNR)** is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

**Capacity Network Resource Interconnection Service** (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

**Capacity Offer** is an offer submitted for inclusion in the Annual Capacity Auction as set forth in Section III.15.4.1 of Market Rule 1.

**Capacity Offer Floor Price** is defined in Section III.A.21.3 of Market Rule 1.

**Capacity Offer Price Threshold (COPT)** is the price specified in Section III.A.22.2.1 of Market Rule 1 associated with the submission, review, and mitigation of prices specified in Capacity Offers submitted for the Annual Capacity Auction.

**Capacity Offer Review Submission Deadline** is the deadline described in the Capacity Auction Calendar by which proposed Capacity Offers and accompanying documentation must be submitted to the Internal Market Monitor in accordance with Section III.A.22.2.2.

~~**Capacity Performance Bilateral** is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 or Section III.15.6.3 of Market Rule 1.~~

**Capacity Performance Payment** is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 or Section III.15.8.2 of Market Rule 1.

**Capacity Performance Payment Rate** is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 or Section III.15.8.2.5 of Market Rule 1.

**Capacity Resource** is a type of resource eligible to participate in the Annual Capacity Auction. There are four types of Capacity Resources: Generating Capacity Resource, Import Capacity Resource, Demand Capacity Resource, and Distributed Energy Capacity Resource.

**Capacity Performance Score** is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 or Section III.15.8.2.4 of Market Rule 1.

**Capacity Rationing Rule** addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

**Capacity Scarcity Condition** is a period during which performance is measured in the Capacity Market, as described in Section III.13.7.2.1 or III.15.8.7.2.1 of Market Rule 1.

**Capacity Supply Obligation** is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2 or an Annual Capacity Auction in accordance with Section III.15.4, a reconfiguration auction in accordance with Section III.13.4 or Section III.15.5, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 or Section III.15.6.1 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 or Section III.15.6.1 of Market Rule 1.

**Capacity Transfer Rights (CTRs)** are calculated in accordance with Section III.13.7.5.4 or Section III.15.8.5.4.

**Capacity Transferring Resource** is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 or Section III.15.6.1, or; (2) a reconfiguration auction, as described in Section III.13.4 or Section III.15.5.

**Capacity Zone** is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

**Capacity Zone Demand Curves** are the demand curves used in the Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3 and in Sections III.15.1.1.2 and III.15.1.1.3.

**Capital Funding Charge (CFC)** is defined in Section IV.B.2 of the Tariff.

**CARL Data** is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

**Category B Designated Blackstart Resource** has the same meaning as Designated Blackstart Resource.

**Charge** is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

**CLAIM10** is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

**CLAIM30** is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

**Claimed Capability Audit** is performed to determine the real power output capability of a Generator Asset, the demand reduction capability of a Demand Response Resource, or the demand reduction capability and energy injection capability of a Demand Response Distributed Energy Resource Aggregation.

**Cluster** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**Cluster Enabling Transmission Upgrade (CETU)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Entry Deadline** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Interconnection System Impact Study (CSIS)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Request Window** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**Cluster Restudy** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**Cluster Study** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**CNR Capability** is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

**Coincident Peak Contribution** is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

**Commercial Capacity** is capacity that has achieved FCM Commercial Operation or Capacity Market Commercial Operation.

**Commission** is the Federal Energy Regulatory Commission.

**Commitment Period** is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

**Common Costs** are those costs associated with a Station that are avoided only if none of the Generating Capacity Resources composing the Station acquire a Capacity Supply Obligation for the Capacity Commitment Period, or by the acceptance of the Deactivation Notification of all Generating Capacity Resources composing 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 Capacity Market Transaction** is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction or Annual Capacity Auction in which multiple Lead Market Participants provide capacity, as described in Section III.13.1.5 or Section III.15.2.8 of Market Rule 1.

**Composite Offer Deadline** is the deadline for submission of the Composite Offer Form described at Section III.15.2.8.

**Composite Offer Form** is a form submitted by Lead Market Participants for separate resources seeking to participate as a single composite Capacity Resource in the Annual Capacity Auction, as described in Section III.15.2.8.

**Confidential Information** is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

**Confidentiality Agreement** is Attachment 1 to the ISO New England Billing Policy.

**Congestion** is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

**Congestion Component** is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

**Congestion Cost** is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

**Congestion Paying LSE** is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

**Congestion Revenue Fund** is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

**Congestion Shortfall** means congestion payments exceed congestion charges during the billing process in any billing period.

**Continuous Storage ATRR** is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage DARD** is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage Generator Asset** is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage Facility** is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Control Agreement** is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

**Control Area** is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and
(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

**Controllable Behind-the-Meter Generation** means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

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

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

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

**Cost-Based Reference Price** is a price determined by the Internal Market Monitor for comparison to a price in a Proposed Capacity Offer submitted pursuant to Section III.A.22.2.3.

**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 and for each Annual Capacity Auction pursuant to Section III.15.1.2.

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

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

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

**Credit Qualifying** means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

**Credit Threshold** consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

**Critical Energy Infrastructure Information (CEII)** is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

**Current Ratio** is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

**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.

**Cyber Security Exigency** is a suspicious or malicious electronic act or event that compromises or attempts to compromise, or disrupts or attempts to disrupt, the ongoing operation of the ISO, the New England Markets, or reliability within the New England Control Area or other electrical facilities directly or indirectly connected to the New England Transmission System and (i) whose severity or nature reasonably requires that the ISO obtain expert assistance not normally called upon to counter such an electronic act or resolve such an event or (ii) whose nature requires the ISO to report such an electronic act or event pursuant to NERC Critical Infrastructure Protection Reliability Standards or applicable regulations promulgated by the Department of Homeland Security, the Department of Energy, or a federal agency with similar cybersecurity responsibilities (or any of their respective successor organizations or agencies).

**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)(1) of Market Rule 1.

**Day-Ahead Ancillary Services** means Day-Ahead Flexible Response Services and Day-Ahead Energy Imbalance Reserve.

**Day-Ahead Ancillary Services Avoidable Input Cost** is defined in Section III.A.8.2.2 of Appendix A of Market Rule 1.

**Day-Ahead Ancillary Services Benchmark Level** is defined in Section III.A.8.2 of Appendix A of Market Rule 1.

**Day-Ahead Ancillary Services Offer Block-Hours** are Block-Hours assigned to the Lead Market Participant for each Day-Ahead Ancillary Services Offer. Blocks of the Day-Ahead Ancillary Services Offer in effect for each hour will be totaled to determine the quantity of Day-Ahead Ancillary Services Offer Block-Hours for a given day.

**Day-Ahead Ancillary Services Expected Close-Out Component** is defined in Section III.A.8.2.1 of Appendix A of Market Rule 1.

**Day-Ahead Ancillary Services Market** means the sale of and payment for Day-Ahead Ancillary Services developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

**Day-Ahead Ancillary Services Offer** is an offer that may be submitted by Market Participants in the Day-Ahead Ancillary Services Market in accordance with Section III.1.8.1 of Market Rule 1, and that is used by the ISO to determine obligations for Day-Ahead Ancillary Services as described in Section III.3.2.1(a)(2) of Market Rule 1.

**Day-Ahead Ancillary Services Strike Price** is specified in Section III.1.8.2 of Market Rule 1.

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

**Day-Ahead Demand Reduction Obligation** is defined in Section III.3.2.1(a)(1) of Market Rule 1.

**Day-Ahead Energy Imbalance Reserve** is a form of reserve capability that is procured in the Day-Ahead Ancillary Services Market to help satisfy the Forecast Energy Requirement Demand Quantity described in Section III.1.8.4 of Market Rule 1.

**Day-Ahead Energy Imbalance Reserve Obligation** is defined in Section III.3.2.1(a)(2) of Market Rule 1.

**Day-Ahead Energy Market** means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

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

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

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

**Day-Ahead 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 Flexible Response Services** means Day-Ahead Ten-Minute Spinning Reserve, Day-Ahead Ten-Minute Non-Spinning Reserve, and Day-Ahead Thirty-Minute Operating Reserve.

**Day-Ahead Flexible Response Services Demand Quantities** means Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, Day-Ahead Total Ten-Minute Reserve Demand Quantity, Day-Ahead Minimum Total Reserve Demand Quantity, and Day-Ahead Total Reserve Demand Quantity.

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

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

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

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

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

**Day-Ahead Market** means the jointly optimized Day-Ahead Energy Market and Day-Ahead Ancillary Services Market.

**Day-Ahead Minimum Total Reserve Demand Quantity** is described in Section III.1.8.3(c) of Market Rule 1.

**Day-Ahead Prices** means the prices resulting from the Day-Ahead Market as described in Section III.2.6 of Market Rule 1.

**Day-Ahead Ten-Minute Non-Spinning Reserve** is a form of ten-minute reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

**Day-Ahead Ten-Minute Non-Spinning Reserve Obligation** is defined in Section III.3.2.1(a)(2) of Market Rule 1.

**Day-Ahead Ten-Minute Spinning Reserve** is a form of ten-minute reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

**Day-Ahead Ten-Minute Spinning Reserve Demand Quantity** is described in Section III.1.8.3(a) of Market Rule 1.

**Day-Ahead Ten-Minute Spinning Reserve Obligation** is described in Section III.3.2.1(a)(2) of Market Rule 1.

**Day-Ahead Thirty-Minute Operating Reserve** is a form of reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

**Day-Ahead Thirty-Minute Operating Reserve Obligation** is defined in Section III.3.2.1(a)(2) of Market Rule 1.

**Day-Ahead Total Ten-Minute Reserve Demand Quantity** is described in Section III.1.8.3(b) of Market Rule 1.

**Day-Ahead Total Reserve Demand Quantity** is described in Section III.1.8.3(d) of Market Rule 1.

**DDP Dispatchable Resource** is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

**Deactivation Notification** is a notification of the planned New England Market Deactivation or Capacity Market Deactivation of a resource, External Elective Transmission Upgrade, or portion thereof, submitted to the ISO by the applicable Lead Market Participant.

**Deactivation Notification Deadline** is the deadline for submission of a Deactivation Notification and a Deactivation Notification Package, as discussed in Section II.52.1 of the OATT.

**Deactivation Notification Package** is information submitted to the ISO, as specified in Section II.52.3 of the OATT, by a resource or External Elective Transmission Upgrade seeking a determination regarding a Deactivation Notification.

**Debt-to-Total Capitalization Ratio** is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders'

equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

**Decrement Bid** means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

**Default Amount** is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

**Default Period** is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

**Delivering Party** is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

**Demand Bid** means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

**Demand Bid Block-Hours** are the Block-Hours assigned to the submitting Customer for each Demand Bid.

**Demand Bid Cap** is $2,000/MWh.

**Demand Capacity Resource** is a type of resource that may participate in the Capacity Market. There are three Demand Capacity Resource types: Active Demand Capacity Resource, On-Peak Demand Capacity Resource, and Seasonal Peak Demand Capacity Resource.

**Demand Designated Entity** is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

**Demand Reduction Offer** is an offer by a Market Participant with a Demand Response Resource to reduce demand.

**Demand Reduction Offer Block-Hours** are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

**Demand Reduction Threshold Price** is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

**Demand Resource On-Peak Hours** are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

**Demand Resource Seasonal Peak Hours** are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

**Demand Response Asset** is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

**Demand Response Available** is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

**Demand Response Baseline** is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

**Demand Response Holiday** is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

**Demand Response Distributed Energy Resource Aggregation (DRDERA)** is a type of Distributed Energy Resource Aggregation that is described in additional detail in Section III.6.5.

**Demand Response Resource** is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

**Demand Response Resource Notification Time** is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

**Demand Response Resource Ramp Rate** is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

**Demand Response Resource Start-Up Time** is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

**Designated Agent** is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20 Service Provider, an Eligible Customer, or a Transmission Customer.

**Designated Blackstart Resource** is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

**Designated Entity** is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

**Designated FCM Participant** is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

**Designated FTR Participant** is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

**Desired Dispatch Point (DDP)** means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

**Direct Assignment Facilities** are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

**Directly Metered Assets** are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

**Disbursement Agreement** is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

**Dispatch Instruction** means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

**Dispatch Zone** means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

**Dispatchable Asset Related Demand (DARD)** is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

**Dispatchable Resource** is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

**Dispute Representatives** are defined in 6.5.c of the ISO New England Billing Policy.

**Disputed Amount** is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

**Disputing Party**, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

**Distributed Energy Capacity Resource (DECR)** is a type of Capacity Resource that participates in the Capacity Market and composes one or more Distributed Energy Resource Aggregations.

**Distributed Energy Resource (DER)** is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation, or demand reduction.

**Distributed Energy Resource Aggregation (DERA)** is an aggregation of Distributed Energy Resources that is registered under Section III.6.7 and is described in additional detail in Section III.6.

**Distributed Energy Resource Aggregator (DER Aggregator)** is a Market Participant that aggregates one or more Distributed Energy Resources for participation in a Distributed Energy Resource Aggregation and serves as the Lead Market Participant for a Distributed Energy Resource Aggregation.

**Distributed Generation** means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

**DRR Aggregation Zone** is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

**Do Not Exceed (DNE) Dispatchable Generator** is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

**Do Not Exceed Dispatch Point** is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

**Dynamic De-List Bid** is a bid submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, Existing Demand Capacity Resources, and Existing Distributed Energy Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

**Dynamic De-List Bid Threshold** is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

**EA Amount** is defined in Section IV.B.2.2 of the Tariff.

**Early Amortization Charge (EAC)** is defined in Section IV.B.2 of the Tariff.

**Early Amortization Working Capital Charge (EAWCC)** is defined in Section IV.B.2 of the Tariff.

**Early Payment Shortfall Funding Amount (EPSF Amount)** is defined in Section IV.B.2.4 of the Tariff.

**Early Payment Shortfall Funding Charge (EPSFC)** is defined in Section IV.B.2 of the Tariff.

**EAWW Amount** is defined in Section IV.B.2.3 of the Tariff.

**EBITDA-to-Interest Expense Ratio** is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

**Economic Dispatch Point** is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

**Economic Maximum Limit or Economic Max** is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy

Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

**Economic Minimum Limit or Economic Min** is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

**Economic Study or Economic Studies** are studies conducted by the ISO pursuant to the process set out in Section 17 of Attachment K to the OATT.

**Effective Offer** is the Supply Offer, Demand Reduction Offer, Demand Bid or Day-Ahead Ancillary Services Offer that is used for NCPC calculation purposes as specified in Section III.F.1(a).

**EFT** is electronic funds transfer.

**Elective Transmission Upgrade** is defined in Section I of Schedule 25 of the OATT.

**Elective Transmission Upgrade Interconnection Customer** is defined in Schedule 25 of the OATT.

**Electric Reliability Organization (ERO)** is defined in 18 C.F.R. § 39.1.

**Electric Storage Facility** is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

**Eligible Customer** is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

**Eligible FTR Bidder** is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

**Emergency** is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

**Emergency Condition** means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

**Emergency Energy** is energy transferred from one control area operator to another in an Emergency.

**Emergency Minimum Limit or Emergency Min** means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

**EMS** is energy management system.

**End-of-Round Price** is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

**End User Participant** is defined in Section 1 of the Participants Agreement.

**Energy** is power produced in the form of electricity, measured in kilowatthours or megawatthours.

**Energy Administration Service (EAS)** is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

**Energy Component** means the Locational Marginal Price at the reference point.

**Energy Efficiency** is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

**Energy Imbalance Service** is the form of Ancillary Service described in Schedule 4 of the OATT.

**Energy Market** is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

**Energy Non-Zero Spot Market Settlement Hours** are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

**Energy Offer Floor** is negative $150/MWh.

**Energy Transaction Units (Energy TUs)** are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, Day-Ahead Ancillary Services Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

**Equipment Damage Reimbursement** is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

**Equivalent Demand Forced Outage Rate (EFORd**) means the portion of time a unit is in demand, but is unavailable due to forced outages.

**Establish Claimed Capability Audit** is the audit performed pursuant to Section III.1.5.1.2.

**Excepted Transaction** is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

**Existing Capacity Qualification Deadline** is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

**Existing Capacity Qualification Package** is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

**Existing Capacity Resource** is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

**Existing Capacity Retirement Deadline** is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

**Existing Capacity Retirement Package** is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

**Existing Demand Capacity Resource** is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

**Existing Distributed Energy Capacity Resource** is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.2 of Market Rule 1.

**Existing Generating Capacity Resource** is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

**Existing Import Capacity Resource** is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

**Expedited Study Request** is defined in Section II.34.7 of the OATT.

**Export-Adjusted LSR** is as defined in Section III.12.4(b)(ii).

**Export Bid** is a bid 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.

**Export Offer Segment** is the total MW quantity of a Capacity Offer that is subject to a contract to export capacity outside the New England Control Area during the Capacity Commitment Period associated with the Capacity Offer, whether such MW quantity is delimited by only one price-quantity pair or multiple price-quantity pairs submitted as part of the Capacity Offer pursuant to Section III.15.4.1.

**Exports** are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

**External Elective Transmission Upgrade (External ETU)** is defined in Section I of Schedule 25 of the OATT.

**External Market Monitor** means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

**External Node** is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

**External Resource** means a generation resource located outside the metered boundaries of the New England Control Area.

**External Transaction** is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

**External Transaction Cap** is $2,000/MWh for External Transactions other than Coordinated External Transactions and $1,000/MWh for Coordinated External Transactions.

**External Transaction Floor** is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative $1,000/MWh for Coordinated External Transactions.

**External Transmission Project** is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

**Facilities Study** is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected

PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

**Facility and Equipment Testing** means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

**Failure to Maintain Blackstart Capability** is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

**Failure to Perform During a System Restoration** is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

**Fast Start Demand Response Resource** is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

**Fast Start Generator** means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

**FCA Qualified Capacity** is the Qualified Capacity that is used in a Forward Capacity Auction.

**FCM Capacity Charge Requirements** are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

**FCM Charge Rate** is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

**FCM Commercial Operation** is defined in Section III.13.3.8 of Market Rule 1.

**FCM Deposit** is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

**FCM Financial Assurance Requirements** are described in Section VII of the ISO New England Financial Assurance Policy.

**Final Forward Reserve Obligation** is calculated in accordance with Section III.9.8(a) of Market Rule 1.

**Financial Assurance Default** results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

**Financial Assurance Obligations** relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

**Financial Transmission Right (FTR)** is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

**Firm Point-To-Point Service** is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

**Firm Transmission Service** is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

**Flexible DNE Dispatchable Generator** is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

**Force Majeure** - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20 Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20 Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20 Service Provider, or any other Transmission Owner, in the case of a Schedule 20 Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20 Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20 Service Provider, or any Transmission Owner.

**Forecast Energy Requirement Demand Quantity** is described in Section III.1.8.4 of Market Rule 1.

**Forecast Energy Requirement Penalty Factor** is a rate, in $/MWh, that is used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of forecast energy requirement shortages and is defined in Section III.2.6.2(d) of Market Rule 1.

**Forecast Energy Requirement Price** is determined in accordance with Section III.2.6.2(b) of Market Rule 1.

**Forward Capacity Auction (FCA)** is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1. The final Forward Capacity Auction was for the Capacity Commitment Period beginning on June 1, 2027.

**Forward Capacity Auction Starting Price** is calculated in accordance with Section III.13.2.4 of Market Rule 1.

**Forward Capacity Market (FCM)** is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

**Forward Energy Inventory Election** is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

**Forward LNG Inventory Election** is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

**Forward Reserve** means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

**Forward Reserve Assigned Megawatts** is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

**Forward Reserve Auction** is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

**Forward Reserve Auction Offers** are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

**Forward Reserve Charge** is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

**Forward Reserve Clearing Price** is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

**Forward Reserve Credit** is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

**Forward Reserve Delivered Megawatts** are calculated in accordance with Section III.9.6.5 of Market Rule 1.

**Forward Reserve Delivery Period** is defined in Section III.9.1 of Market Rule 1.

**Forward Reserve Failure-to-Activate Megawatts** are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

**Forward Reserve Failure-to-Activate Penalty** is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

**Forward Reserve Failure-to-Activate Penalty Rate** is specified in Section III.9.7.2 of Market Rule 1.

**Forward Reserve Failure-to-Reserve**, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

**Forward Reserve Failure-to-Reserve Megawatts** are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

**Forward Reserve Failure-to-Reserve Penalty** is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

**Forward Reserve Failure-to-Reserve Penalty Rate** is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

**Forward Reserve Fuel Index** is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

**Forward Reserve Heat Rate** is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

**Forward Reserve Market** is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

**Forward Reserve MWs** are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

**Forward Reserve Obligation** is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

**Forward Reserve Obligation Charge** is defined in Section III.10.4 of Market Rule 1.

**Forward Reserve Offer Cap** is $7,100/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. As described in Section III.9.1, the final Forward Reserve Procurement Period shall run from October 1, 2024 through February 28, 2025.

**Forward Reserve Qualifying Megawatts** refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

**Forward Reserve Resource** is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

**Forward Reserve Threshold Price** is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

**FTR Auction** is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

**FTR Auction Revenue** is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

**FTR Credit Test Percentage** is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

**FTR Financial Assurance Requirements** are described in Section VI of the ISO New England Financial Assurance Policy.

**FTR Holder** is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

**FTR-Only Customer** is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

**FTR Settlement Risk Financial Assurance** is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

**GADS Data** means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

**Gap Request for Proposals (Gap RFP)** is defined in Section III.11 of Market Rule 1.

**Gas Day** means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

**Generating Capacity Resource** means a type of resource participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2..

**Generator Asset** is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

**Generator Imbalance Service** is the form of Ancillary Service described in Schedule 10 of the OATT.

**Generator Interconnection Related Upgrade** is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

**Generator Owner** is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

**Good Utility Practice** means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

**Governance Only Member** is defined in Section 1 of the Participants Agreement.

**Governance Participant** is defined in the Participants Agreement.

**Governing Documents**, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

**Governing Rating** is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

**Grandfathered Agreements (GAs)** is a transaction specified in Section II.45 for the applicable period specified in that Section.

**Grandfathered Intertie Agreement (GIA)** is defined pursuant to the TOA.

**Handy-Whitman Index of Public Utility Construction Costs** is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

**Highgate Transmission Facilities (HTF)** are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

**Host Participant or Host Utility** is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

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

**Hourly 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** is a type of resource participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2.

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

**Inadvertent Energy Revenue Charges or Credits** is defined in Section III.3.2.1(p) of Market Rule 1.

**Inadvertent Interchange** means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

**Increment Offer** means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

**Incremental ARR** is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

**Incremental ARR Holder** is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

**Incremental Cost of Reliability Service** is described in Section II.54.5 of the OATT..

**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.

**Initial State of Charge** is the State of Charge that an Electric Storage Facility offers at the start of hour one of the Day-Ahead Energy Market.

**Installed Capacity Requirement** means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

**Interchange Transactions** are transactions deemed to be effected under Market Rule 1.

**Interconnecting Transmission Owner** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Interconnection Agreement** is the "Large Generator Interconnection Agreement", the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement" pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

**Interconnection Customer** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Interconnection Procedure** is the "Large Generator Interconnection Procedures," the "Small Generator Interconnection Procedures," or the "Elective Transmission Upgrade Interconnection Procedures" pursuant to Schedules 22, 23, and 25 of the ISO OATT.

**Interconnection Reliability Operating Limit (IROL)** has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

**Interconnection Request** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

**Interconnection Rights Holder(s) (IRH)** has the meaning given to it in Schedule 20A to Section II of this Tariff.

**Interest** is interest calculated in the manner specified in Section II.8.3.

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

**Intermittent Power Resource** is a wind, solar, run of river hydro or other renewable resource or an aggregation of wind, solar, run of river hydro and other renewable resources that does not have control over its net power output.

**Internal Bilateral for Load** is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

**Internal Bilateral for Market for Energy** is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

**Internal Elective Transmission Upgrade (Internal ETU)** is defined in Section I of Schedule 25 of the OATT.

**Internal Market Monitor** means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

**Interregional Planning Stakeholder Advisory Committee (IPSAC)** is the committee described as such in the Northeast Planning Protocol.

**Interregional Transmission Project** is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

**Interruption Cost** is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

**Inventoried Energy Day** is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported

by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

**Investment Grade Rating,** for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

**Invoice** is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

**Invoice Date** is the day on which the ISO issues an Invoice.

**ISO** means ISO New England Inc.

**ISO Charges**, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

**ISO Control Center** is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

**ISO-Initiated Claimed Capability Audit** is the audit performed pursuant to Section III.1.5.1.4.

**ISO New England Administrative Procedures** means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

**ISO New England Billing Policy** is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

**ISO New England Filed Documents** means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

**ISO New England Financial Assurance Policy** is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

**ISO New England Information Policy** is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

**ISO New England Manuals** are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

**ISO New England Operating Documents** are the Tariff and the ISO New England Operating Procedures.

**ISO New England Operating Procedures (OPs)** are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

**ISO New England Planning Procedures** are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

**ISO New England System Rules** are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

**ITC Agreement** is defined in Attachment M to the OATT.

**ITC Rate Schedule** is defined in Section 3.1 of Attachment M to the OATT.

**ITC System** is defined in Section 2.2 of Attachment M to the OATT.

**ITC System Planning Procedures** is defined in Section 15.4 of Attachment M to the OATT.

**Joint ISO/RTO Planning Committee (JIPC)** is the committee described as such in the Northeastern Planning Protocol.

**Late Payment Account** is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

**Late Payment Account Limit** is defined in Section 4.2 of the ISO New England Billing Policy.

**Late Payment Charge** is defined in Section 4.1 of the ISO New England Billing Policy.

**Lead Market Participant,** for purposes other than the Forward Capacity Market or Annual Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids, Demand Reduction Offers, Baseline Deviation Offers, or Day-Ahead Ancillary Services 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. For purposes of the Annual Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of a Capacity Resource.

**Limited Energy Resource** means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

**Load Asset** means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

**Load Management** means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

**Load Shedding** is the systematic reduction of system demand by temporarily decreasing load.

**Load-Side Relationship Certification** is a certification described in Section III.A.21.1.4 that a Lead Market Participant submits as part of a submission of information pursuant to Section III.A.21.1.5 to demonstrate that certain capacity should not be subject to buyer-side market power review.

**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 Longer-Term Transmission Upgrade** is any addition, modification, and/or upgrade to the New England Transmission System with a voltage level below 115 kV that is required in connection with the

construction of a Longer-Term Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Section 16 of Attachment K to the OATT.

**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 115 kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

**Local Resource Adequacy Requirement** is calculated pursuant to Section III.12.2.1.1.

**Local Second Contingency Protection Resources** are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

**Local Service** is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

**Local Service Schedule** is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

**Local Sourcing Requirement (LSR)** is a value calculated as described in Section III.12.2.1 of Market Rule 1.

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

**Localized Costs** are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 and Section 10 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

**Location** is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

**Locational Marginal Price (LMP)** is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

**Long-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.

**Longer-Term Proposal** is a proposal submitted by a Qualified Transmission Project Sponsor pursuant to Section 16.4(b) of Attachment K to the OATT.

**Longer-Term Transmission Solution** is the Longer-Term Proposal identified as the preferred solution pursuant to Section 16 of Attachment K to the OATT.

**Longer-Term Transmission Study** is a study conducted by the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. The 2050 Transmission Study shall be the first Longer-Term Transmission Study.

**Longer-Term Transmission Upgrade** is an addition, modification, and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Longer-Term Transmission Upgrade PTF classification specified in the OATT and has been included in the Regional System Plan and RSP Project List as a Longer-Term Transmission Upgrade pursuant to the procedures described in Section 16 of Attachment K of the OATT.

**Loss Component** is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

**Loss of Load Expectation (LOLE)** is the probability of disconnecting non-interruptible customers due to a resource deficiency.

**Lost Opportunity Cost (LOC)** is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

**LSE** means load serving entity.

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

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

**Manual Response Rate** is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

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

**Marginal Reliability Impact** is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

**Market Credit Limit** is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

**Market Credit Test Percentage** is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

**Market 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 Service Agreement (MPSA)** is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

**Market Rule 1** is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

**Market Violation** is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

**Material Adverse Change** is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

**Material Adverse Impact** is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

**Maximum Capacity Limit** is a value calculated as described in Section III.12.2.2 of Market Rule 1.

**Maximum Consumption Limit** is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

**Maximum Daily Award Limit** is a parameter that may be submitted as part of a Day-Ahead Ancillary Services Offer, as described in Section III.1.8.1, that expresses the maximum total megawatt-hours of Day-Ahead energy offered or bid and Day-Ahead Ancillary Services offered for the next Operating Day.

**Maximum Daily Energy Limit** is the maximum amount of megawatt-hours that a Limited Energy Resource expects to be able to generate in the next Operating Day.

**Maximum Daily Consumption Limit** is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

**Maximum Facility Load** is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

**Maximum Interruptible Capacity** is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

**Maximum Load** is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

**Maximum Number of Daily Starts** is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

**Maximum Reduction** is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

**Maximum State of Charge** is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, above which the ISO shall not schedule the Electric Storage Facility to receive electricity from the grid.

**Measure Life** is the estimated time an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the

Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction, Annual Capacity Auction, or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

**Measurement and Verification Documents** mean the measurement and verification documents described in Section III.13.1.4.3.1 and Section III.15.2.1.1.2.1 of Market Rule 1 that are submitted by On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

**Measurement and Verification Plan** means the measurement and verification plan submitted by an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1, or as part of the qualification process for the Annual Capacity Auction pursuant to the requirements of Section III.15.2.1.1.2.1 of Market Rule 1, and the ISO New England Manuals.

**Measurement and Verification Reference Reports** are optional reports submitted by On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

**Measurement and Verification Summary Report** is the monthly report submitted by an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource with the monthly settlement

report for the Forward Capacity Market or Annual Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity 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.

**Metered Quantity For Settlement** is defined in Section III.3.2.1.1 of Market Rule 1.

**Minimum Consumption Limit** is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

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

**Minimum Generation Emergency** means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

**Minimum Generation Emergency Credits** are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

**Minimum Reduction** is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

**Minimum Reduction Time** is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

**Minimum Run Time** is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its

Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

**Minimum State of Charge** is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, below which the ISO shall not schedule the Electric Storage Facility to inject electricity to the grid.

**Minimum Time Between Reductions** is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

**Minimum Total Reserve Requirement**, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

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

**Monthly Capacity Payment** is the Capacity Market payment described in Section III.13.7.3 or Section III.15.8.3 of Market Rule 1.

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

**Monthly Qualified Capacity** is the amount of a resource's Qualified Capacity eligible to participate in a Monthly Reconfiguration Auction or Capacity Supply Obligation Bilateral during the applicable month.

**Monthly Real-Time Demand Reduction Obligation** is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

**Monthly Real-Time Generation Obligation** is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

**Monthly Real-Time Load Obligation** is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

**Monthly Reconfiguration Auction** is the reconfiguration auction conducted by the ISO each month as described in Section III.13.4.7 for those Monthly Reconfiguration Auctions held for months prior to the Capacity Commitment Period beginning on June 1, 2028 and in Section III.15.5 for those Monthly Reconfiguration Auctions held for months subsequent to the start of the Capacity Commitment Period beginning on June 1, 2028.

**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 ninth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

**MRI Transition Period** is the period specified in Section III.13.2.2.1.

**MUI** is the market user interface.

**Municipal Market Participant** is defined in Section II of the ISO New England Financial Assurance Policy.

**MW** is megawatt.

**MWh** is megawatt-hour.

**Native Load Customers** are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

**NCPC Charge** means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

**NCPC Credit** means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

**Needs Assessment** is defined in Section 4.1 of Attachment K to the OATT.

**NEMA**, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

**NEMA Contract** is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

**NEMA Load Serving Entity (NEMA LSE)** is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

**NEMA or Northeast Massachusetts Upgrade**, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

**NEPOOL** is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

**NEPOOL Agreement** is the agreement among the participants in NEPOOL.

**NEPOOL GIS** is the generation information system.

**NEPOOL GIS Administrator** is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

**NEPOOL GIS API Fees** are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that

accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

**NEPOOL Participant** is a party to the NEPOOL Agreement.

**NERC** is the North American Electric Reliability Corporation or its successor organization.

**NESCOE** is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

**Net Commitment Period Compensation (NCPC)** is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

**Net CONE** is an estimate of the Cost of New Entry, net of non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require to be economically viable given reasonable expectations of the energy and ancillary services revenues under long-term equilibrium conditions.

**Net Regional Clearing Price** is described in Section III.13.7.5 or Section III.15.8.5 of Market Rule 1.

**Net Supply** is energy injected into the transmission or distribution system at a Retail Delivery Point.

**Net Supply Capability** is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

**Network Capability Interconnection Standard** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Network Customer** is a Transmission Customer receiving RNS or LNS.

**Network Import Capability (NI Capability)** is defined in Section I of Schedule 25 of the OATT.

**Network Import Interconnection Service (NI Interconnection Service)** is defined in Section I of Schedule 25 of the OATT.

**Network Resource** is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired or deactivated; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired or deactivated, 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.

**Network Upgrades** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**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, New Demand Capacity Resource, or New Distributed Energy Capacity Resource.

**New Capacity Qualification Deadline** is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

**New Capacity Qualification Package** is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule

1.

**New Capacity Resource** is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

**New Capacity Show of Interest Form** is a form applicable to the Forward Capacity Market 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 applicable to the Forward Capacity Market during which a Project Sponsor may submit a New Capacity Show of Interest Form, a New Demand Capacity Resource Show of Interest Form, or a New Distributed Energy Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

**New Demand Capacity Resource** is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

**New Demand Capacity Resource Qualification Package** is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

**New Demand Capacity Resource Show of Interest Form** is a form applicable to the Forward Capacity Market described in Section III.13.1.4.1.1.1 of Market Rule 1.

**New Distributed Energy Capacity Resource** is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.1 of Market Rule 1.

**New Distributed Energy Capacity Resource Qualification Package** is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4A.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource.

**New Distributed Energy Capacity Resource Show of Interest Form** is a form applicable to the Forward Capacity Market described in Section III.13.1.4A.1.1.1 of Market Rule 1.

**NECEC Transmission LLC (NECEC)** is defined in Schedule 20B to Section II of this Tariff.

**New England Clean Energy Connect Transmission Line (NECEC Transmission Line)** is defined in Schedule 20B to Section II of this Tariff.

**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 Deactivation** is the permanent removal of a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource from all New England Markets, or the permanent reduction in Capacity Network Import Capability and Network Import Capability of an External Elective Transmission Upgrade, as described in Section II.I of the OATT.

**New England Markets** are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

**New England System Restoration Plan** is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

**New England Transmission System** is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

**New Generating Capacity Resource** is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

**New Import Capacity Resource** is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

**NMPTC** means Non-Market Participant Transmission Customer.

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

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

**Node** is a point on the New England Transmission System at which LMPs are calculated.

**No-Load Fee** is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

**Nominated Consumption Limit** is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.2.1 or Section III.15.8.5.2.1.

**Non-Commercial Capacity** is the capacity of a resource that cleared in a Forward Capacity Auction for periods prior to the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, or otherwise acquired a Capacity Supply Obligation and remains on Critical Path Schedule monitoring as of June 1, 2028, for some or all of its capacity that acquired a Capacity Supply Obligation.

**Non-Commercial Capacity Cure Period** is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

**Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount**) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity

Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

**Non-Designated Blackstart Resource Study Cost Payments** are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

**Non-Dispatchable Resource** is any Resource that does not meet the requirements to be a Dispatchable Resource.

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

**Non-Hourly Requirements** are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

**Non-Incumbent Transmission Developer** is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

**Non-Incumbent Transmission Developer Operating Agreement (or NTDOA)** is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

**Non-Market Participant** is any entity that is not a Market Participant.

**Non-Market Participant Transmission Customer** is any entity which is not a Market Participant but is a Transmission Customer.

**Non-Municipal Market Participant** is defined in Section II of the ISO New England Financial Assurance Policy.

**Non-PTF Transmission Facilities (Non-PTF)** are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

**Non-Qualifying** means a Market Participant that is not a Credit Qualifying Market Participant.

**Notice of RBA** is defined in Section 6.3.2 of the ISO New England Billing Policy.

**Notification Time** is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

**Northeastern Planning Protocol** is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

**NPCC** is the Northeast Power Coordinating Council.

**Obligation Month** means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

**Offer Data** means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

**Offered CLAIM10** is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

**Offered CLAIM30** is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

**On-Peak Demand Capacity Resource** is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

**Open Access Same-Time Information System (OASIS)** is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

**Open Access Transmission Tariff (OATT)** is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

**Operating Authority** is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

**Operating Data** means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

**Operating Day** means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

**Operating Reserve** means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

**Operations Date** is February 1, 2005.

**OTF Service** is transmission service over OTF as provided for in Schedule 20.

**Other Transmission Facility (OTF)** are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System.

**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 for the Phase I/II HVDC-TF and the NECEC Transmission Operating Agreement for the NECEC Transmission Line. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

**Other Transmission Owner (OTO)** is an owner of OTF.

**Ownership Share** is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

**Participant Expenses** are defined in Section 1 of the Participants Agreement.

**Participant Required Balance** is defined in Section 5.3 of the ISO New England Billing Policy.

**Participant Vote** is defined in Section 1 of the Participants Agreement.

**Participants Agreement** is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

**Participants Committee** is the principal committee referred to in the Participants Agreement.

**Participating Transmission Owner (PTO)** is a transmission owner that is a party to the TOA.

**Passive DR Audit** is the audit performed pursuant to Section III.13.6.1.5.4 or Section III.15.7.1.5.4.

**Passive DR Auditing Period** is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources.

**Payment** is a sum of money due to a Covered Entity from the ISO.

**Payment Default Shortfall Fund** is defined in Section 5.1 of the ISO New England Billing Policy.

**Permanent De-list Bid** is a bid submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

**Phase I Transfer Credit** is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

**Phase I/II HVDC-TF** is defined in Schedule 20A to Section II of this Tariff.

**Phase I/II HVDC-TF Transfer Capability** is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The "Phase II Transfer Capability" is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

**Phase One Proposal** is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

**Phase II Transfer Credit** is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

**Phase Two Solution** is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade by a Qualified Transmission Project Sponsor.

**Planning Advisory Committee** is the committee described in Attachment K of the OATT.

**Planning and Reliability Criteria** is defined in Section 3.3 of Attachment K to the OATT.

**Planning Authority** is an entity defined as such by the North American Electric Reliability Corporation.

**Point(s) of Delivery (POD)** is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

**Point of Interconnection** shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

**Point(s) of Receipt (POR)** is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

**Point-To-Point Service** is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

**Policy Scenario** is an Economic Study reference scenario that is described in Section 17.2(c) of Attachment K to the OATT.

**Pool-Planned Unit** is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

**Pool PTF Rate** is the transmission rate determined in accordance with Schedule 8 to the OATT.

**Pool RNS Rate** is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

**Pool-Scheduled Resources** are described in Section III.1.10.2 of Market Rule 1.

**Pool Supported PTF** is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

**Pool Transmission Facility (PTF)** means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

**Posting Entity** is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

**Posture** means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

**Posturing Credits** are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

**Power Purchaser** is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

**Principal** is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the

Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

**Profiled Load Assets** include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

**Project Sponsor** is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource, New Demand Capacity Resource, or New Distributed Energy Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

**Proposed Capacity Offer** is an offer submitted to the Internal Market Monitor for its review pursuant to Section III.A.22.2.3.

**Proportional Impact Method** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

**Proxy Capacity Offer** is a type of offer used in the Annual Capacity Market.

**Proxy De-List Bid** was a type of bid used in the Forward Capacity Market.

**Provisional Member** is defined in Section I.68A of the Restated NEPOOL Agreement.

**PTO Administrative Committee** is the committee referred to in Section 11.04 of the TOA.

**Public Policy Requirement** is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

**Public Policy Transmission Study** is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a

rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

**Public Policy Local Transmission Study** is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

**Public Policy Transmission Upgrade** is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

**Publicly Owned Entity** is defined in Section I of the Restated NEPOOL Agreement.

**Qualification Data Submission Deadline** is a date specified in the Capacity Auction Calendar by which a Lead Market Participant seeking to have a resource participate in the Annual Capacity Auction must submit qualification materials pursuant to Section III.15.2.1.1.

**Qualification Data Submission Package** is the package submitted to the ISO by a Lead Market Participant seeking to qualify a resource for the Annual Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral pursuant to Section III.15.2.1.1.

**Qualification Process Cost Reimbursement Deposit** is described in Section III.13.1.9.3 of Market Rule 1 and shall apply to all resources subject to Section III.15.A 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 prior to the 2028-2029 Capacity Commitment Period in the Forward Capacity Market qualification processes, or, for the 2028-2029 Capacity Commitment Period

and all Capacity Commitment Periods thereafter, through the Annual Capacity Market qualification and demonstration processes.

**Qualified Capacity Challenge and Restoration Plan Submission Window** is the period set forth in the Capacity Auction Calendar during which a Lead Market Participant may challenge the ISO-calculated summer and winter Qualified Capacity values of a Capacity Resource or submit a restoration plan to remedy a significant decrease in a Seasonal Qualified Capacity value of a Capacity Resource.

**Qualified Capacity Challenge and Restoration Plan Submission Deadline** is a date set forth in the Capacity Auction Calendar by which a Lead Market Participant may challenge the ISO-calculated summer and winter Qualified Capacity values of a Capacity Resource or submit a restoration plan to remedy a significant decrease in Qualified Capacity of a Capacity Resource..

**Qualified Generator Reactive Resource(s)** is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

**Qualified Non-Generator Reactive Resource(s)** is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

**Qualified Reactive Resource(s)** is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

**Qualified Transmission Project Sponsor** is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

**Queue Position** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Rapid Response Pricing Asset** is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

**Rapid Response Pricing Opportunity Cost** is the NCPC Credit described in Section III.F.2.3.10.

**Rated** means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

**Rating Agencies** are Standard and Poor's (S&P), Moody's, and Fitch.

**Rationing Minimum Limit** is the MW quantity below which a Capacity Offer may not be rationed in the Annual Capacity Auction.

**RBA Decision** is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

**Reactive Capability Audit** is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

**Reactive Resource** is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

**Reactive Supply and Voltage Control Service** is the form of Ancillary Service described in Schedule 2 of the OATT.

**Real-Time** is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

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

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

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

**Real-Time Congestion Revenue** is defined in Section III.3.2.1(i) of Market Rule 1.

**Real-Time Demand Reduction Obligation** is defined in Section III.3.2.1(c) of Market Rule 1.

**Real-Time Demand Reduction Obligation Deviation** is defined in Section III.3.2.1(e) of Market Rule 1.

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

**Real-Time Energy Inventory** is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

**Real-Time Energy Market** means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

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

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

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

**Real-Time Energy Market NCPC Credits** are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

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

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

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

**Real-Time High Operating Limit** is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 or Section III.15.7.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

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

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

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

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

**Real-Time Loss Revenue** is defined in Section III.3.2.1(l) of Market Rule 1.

**Real-Time Loss Revenue Charges or Credits** are defined in Section III.3.2.1(m) of Market Rule 1.

**Real-Time NCP Load Obligation** is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

**Real-Time Offer Change** is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

**Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Prices** means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

**Real-Time Reserve Charge** is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

**Real-Time Reserve Clearing Price** is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

**Real-Time Reserve Credit** is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

**Real-Time Reserve Designation** is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

**Real-Time Reserve Opportunity Cost** is defined in Section III.2.7A(b) of Market Rule 1.

**Real-Time SATOA Obligation** is defined in Section III.3.2.1(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.7 of Appendix A of Market Rule 1.

**Regional Benefit Upgrade(s) (RBU)** means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a System 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). 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. A Network Customer's Monthly Regional Network Load shall be calculated in accordance with Section II.21.2 of the OATT.

**Regional Network Service (RNS)** is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

**Regional Planning Dispute Resolution Process** is described in Section 12 of Attachment K to the OATT.

**Regional System Plan (RSP)** is the plan developed under the process specified in Attachment K of the OATT.

**Regional Transmission Service (RTS)** is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

**Regulation** is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

**Regulation and Frequency Response Service** is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

**Regulation Capacity** is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

**Regulation Capacity Requirement** is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

**Regulation Capacity Offer** is an offer by a Market Participant to provide Regulation Capacity.

**Regulation High Limit** is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

**Regulation Low Limit** is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

**Regulation Market** is the market described in Section III.14 of Market Rule 1.

**Regulation Resources** are those Alternative Technology Regulation Resources and Generator Assets that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

**Regulation Service** is the change in output or consumption made in response to changing AGC SetPoints.

**Regulation Service Requirement** is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

**Regulation Service Offer** is an offer by a Market Participant to provide Regulation Service.

**Related Person** is defined pursuant to Section 1.1 of the Participants Agreement.

**Related Transaction** is defined in Section III.1.4.3 of Market Rule 1.

**Reliability Administration Service (RAS)** is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

**Reliability Committee** is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

**Reliability Markets** are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, the Annual 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 system efficiency benefits as well as reliability benefits to the New England Transmission System.

**Remittance Advice** is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

**Remittance Advice Date** is the day on which the ISO issues a Remittance Advice.

**Renewable Technology Resource** is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

**Re-Offer Period** is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

**Replacement Reserve** is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

**Request for Alternative Proposals (RFAP)** is the request described in Attachment K of the OATT.

**Requested Billing Adjustment (RBA)** is defined in Section 6.1 of the ISO New England Billing Policy.

**Required Balance** is an amount as defined in Section 5.3 of the Billing Policy.

**Reseller** is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

**Reserve Adequacy Analysis** is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

**Reserve Constraint Penalty Factors (RCPFs)** are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1, and that are used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of Day-Ahead Flexible Response Services shortages and defined in Section III.2.6.2(c) of Market Rule 1.

**Reserve Quantity For Settlement** is defined in Section III.10.1 of Market Rule 1.

**Reserve Zone** is defined in Section III.2.7 of Market Rule 1.

**Reserved Capacity** is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

**Resource** means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, a Demand Response Resource, a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation.

**Resource Adequacy Assessment Qualified Capacity** is the amount of summer and winter Qualified Capacity determined pursuant to Section III.15.3 of Market Rule 1 for all Capacity Resources identified in Section III.12.7.2(a) of Market Rule 1, at the start of the Resource Adequacy Assessment process that begins in June of the year preceding the relevant Capacity Commitment Period.

**Restated New England Power Pool Agreement (RNA)** is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

**Rest-of-Pool Capacity Zone** is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

**Rest of System** is an area established under Section III.2.7(d) of Market Rule 1.

**Retail Delivery Point** is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

**Retirement De-List Bid** is a bid in the Forward Capacity Market to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

**Returning Market Participant** is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

**Revenue Requirement** is defined in Section IV.A.2.1 of the Tariff.

**Reviewable Action** is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

**Reviewable Determination** is defined in Section 12.4(a) of Attachment K to the OATT.

**Round-Trip Efficiency** is a percentage expressing the megawatt-hours of energy that an Electric Storage Facility injects onto the grid per megawatt-hour of energy it receives from the grid.

**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.

**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 20 Service Provider (SSP)** references Schedule 20A Service Providers and/or Schedule 20B Service Provider.

**Schedule 20A Service Provider** is defined in Schedule 20A to Section II of this Tariff.

**Schedule 20B Service Provider** refers to NECEC as defined in Schedule 20B to Section II of this Tariff.

**Scheduling Service**, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

**Scheduling, System Control and Dispatch Service**, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

**Seasonal Claimed Capability** is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

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

**Seasonal DR Audit** is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

**Seasonal Peak Demand Capacity Resource** is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

**Seasonal Qualified Capacity Notification Date** is a date described in the Capacity Auction Calendar by which the ISO shall notify Market Participants of their Seasonal Qualified Capacity for the upcoming Capacity Commitment Period.

**Seasonal Qualified Capacity Values** are the summer and winter Qualified Capacity calculated by the ISO pursuant to Section 15.2.7.

**Section III.1.4 Transactions** are defined in Section III.1.4.2 of Market Rule 1.

**Section III.1.4 Conforming Transactions** are defined in Section III.1.4.2 of Market Rule 1.

**Security Agreement** is Attachment 1 to the ISO New England Financial Assurance Policy.

**Selected Qualified Transmission Project Sponsor** is the Qualified Transmission Project Sponsor that proposed the Phase Two Solution, Stage Two Solution, Longer-Term Proposal, or System Efficiency Transmission Upgrade Proposal that has been identified by the ISO as the preferred Phase Two Solution, Stage Two Solution, Longer-Term Transmission Solution, or System Efficiency Transmission Upgrade Solution.

**Selected Qualified Transmission Project Sponsor Agreement** is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

**Self-Schedule** is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to

provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction in the Day-Ahead Energy Market, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction subject to the conditions specified in Section III.1.10.1A(b)(iii) and (iv). For an External Transaction in the Real-Time Energy Market, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of LMP. Demand Response Resources are not permitted to Self-Schedule.

**Self-Supplied FCA Resource** is described in Section III.13.1.6 of Market Rule 1.

**Self-Supplied Capacity Resource** is described in Section III.15.2.9.1 of Market Rule 1.

**Senior Officer** means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that officer.

**Service Agreement** is a Transmission Service Agreement or an MPSA.

**Service Commencement Date** is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

**Services** means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

**Settlement Financial Assurance** is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

**Settlement Only Distributed Energy Resource Aggregation (SODERA)** is a type of Distributed Energy Resource Aggregation and is described in additional detail in Section III.6.6.

**Settlement Only Resources** are generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

**Shortfall Funding Arrangement**, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

**Short-Term** is a period of less than one year.

**Significantly Reduced Congestion Costs** are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

**SMD Effective Date** is March 1, 2003.

**Solar High Limit** is the estimated power output (MW) of a solar Generator Asset given the Real-Time solar and weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

**Solar Plant Future Availability** is the forecasted Real-Time High Operating Limit of a solar Generator Asset, calculated in the manner described in the ISO Operating Documents.

**Solutions Study** is described in Section 4.2(b) of Attachment K to the OATT.

**Special Constraint Resource (SCR)** is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

**Special Constraint Resource Service** is the form of Ancillary Service described in Schedule 19 of the OATT.

**Specified-Term Blackstart Capital Payment** is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

**Sponsored Policy Resource** is a resource, each asset of which: receives a revenue source, other than revenues from ISO-administered markets, that is supported by a government-regulated rate, charge, or other regulated cost recovery mechanism, and; qualifies as a renewable, clean, zero carbon, or alternative energy asset under a renewable energy portfolio standard, clean energy standard, decarbonization or net-zero carbon standard, alternative energy portfolio standard, renewable energy goal, clean energy goal, or decarbonization or net-zero carbon goal enacted by federal or New England state statute, regulation, or executive or administrative order and as a result of which the asset receives the revenue source.

**Stage One Proposal** is a first round submission, as defined in Section 4A.6 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.8 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

**Stakeholder-Requested Scenario** is an Economic Study reference scenario that is described in Section 17.2(d) of Attachment K to the OATT.

**Standard Blackstart Capital Payment** is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

**Start-of-Round Price** is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

**Start-Up Fee** is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

**Start-Up Time** is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

**State Estimator** means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

**State of Charge** is the total quantity of megawatt-hours available to be injected by an Electric Storage Facility onto the grid.

**State-identified Requirement** refers to a legal requirement, mandate or policy of a New England state or local government that forms the basis for a Longer-Term Transmission Study request submitted to the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT.

**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 submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

**Station** is one or more Generating Capacity Resources consisting of one or more assets located within a common property boundary.

**Station Going Forward Common Costs** are the net costs associated with a Station that are avoided only if none of the Generating Capacity Resources composing the Station acquire a Capacity Supply Obligation for the Capacity Commitment Period, or by deactivating all Generating Capacity Resources composing the Station.

**Station-level Blackstart O&M Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Station-level Specified-Term Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Storage as Transmission-Only Asset (SATOA)** is electric storage equipment that: (1) is connected to or to be connected to Pool Transmission Facilities in the New England Transmission System at a voltage level of 115 kV or higher; (2) the ISO approved to be included in the Regional System Plan and RSP Project List as a regulated transmission solution and Pool Transmission Facility pursuant to the regional system planning processes in Attachment K of the OATT; and (3) is capable of receiving energy only from the Pool Transmission Facilities and storing the energy for later injection to the Pool Transmission Facilities.

**Station-level Standard Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Storage DARD** is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Substation Network Upgrades** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**Summer ARA Qualified Capacity** is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

**Summer Capability Period** means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

**Summer Intermittent Reliability Hours** are defined in Section III.13.1.2.2.2.1(c) or Section III.15.3.2.1(b) 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 Efficiency Needs Assessment** is defined in Section 17.9 of Attachment K to the OATT.

**System Efficiency Needs Scenario** is an Economic Study reference scenario that is described in Section 17.2(b) of Attachment K to the OATT.

**System 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 financial benefits they provide exceed the cost of the transmission addition or upgrade.

**System Efficiency Transmission Upgrade Proposal** is a proposal submitted by a Qualified Transmission Project Sponsor pursuant to Section 17.12 of Attachment K to the OATT

**System Efficiency Transmission Upgrade Solution** is the System Efficiency Transmission Upgrade Proposal identified as the preferred solution pursuant to Section 17.12 of Attachment K to the OATT.

**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 Network Upgrades** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**System Operator** shall mean ISO New England Inc. or a successor organization.

**System Operating Limit (SOL)** has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

**System-Wide Capacity Demand Curve** is the demand curve used in the Capacity Market as specified in Section III.13.2.2 or Section III.15.1.1.1.

**TADO** is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

**Tangible Net Worth** is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net

of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

**Technical Committee** is defined in Section 8.2 of the Participants Agreement.

**Ten-Minute Non-Spinning Reserve (TMNSR)** is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

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

**Ten-Minute Reserve Requirement** is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**Ten-Minute Spinning Reserve (TMSR)** is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

**Ten-Minute Spinning Reserve Requirement** is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**Ten-Minute Spinning Reserve Service** is the form of Ancillary Service described in Schedule 5 of the OATT.

**Third-Party Sale** is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

**Thirty-Minute Operating Reserve (TMOR)** is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

**Thirty-Minute Operating Reserve Service** is the form of Ancillary Service described in Schedule 7 of the OATT.

**Through or Out Rate (TOUT Rate)** is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

**Through or Out Service (TOUT Service)** means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

**Tie-Line Asset** is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

**Total Available Amount** is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

**Total Blackstart Capital Payment** is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

**Total Blackstart Service Payments** is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

**Total Reserve Requirement**, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**Total System Capacity** is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

**Transaction Unit (TU)** is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

**Transition Period**: The six-year period commencing on March 1, 1997.

**Transmission Charges**, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

**Transmission Congestion Credit** means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

**Transmission Congestion Revenue** is defined in Section III.5.2.5(a) of Market Rule 1.

**Transmission Constraint Penalty Factors** are described in Section III.1.7.5 of Market Rule 1.

**Transmission Credit Limit** is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

**Transmission Credit Test Percentage** is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

**Transmission Customer** is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20 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 20 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; the Schedule 20B Service Provider for NECEC Transmission Line Transmission Service as provided under Schedule 20B 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 20 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.

**Transitional Cluster Study** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**Transitional CNR Group Study** has the meaning specified in Section I of Schedule 22, Section I of 23, and Section I of 25 of the OATT.

**UDS** is unit dispatch system software.

**Unconstrained Export Transaction** is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

**Uncovered Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Uncovered Transmission Default Amounts** are defined in Section 3.4.f of the ISO New England Billing Policy.

**Unrated** means a Market Participant that is not a Rated Market Participant.

**Unsecured Covered Entity** is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

**Unsecured Municipal Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Unsecured Municipal Market Participant** is defined in Section 3.3(h) of the ISO New England Billing Policy.

**Unsecured Municipal Transmission Default Amount** is defined in Section 3.4.f of the ISO New England Billing Policy.

**Unsecured Non-Municipal Covered Entity** is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

**Unsecured Non-Municipal Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Unsecured Non-Municipal Transmission Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Unsecured Transmission Default Amounts** are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

**Unsettled FTR Financial Assurance** is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

**Updated Measurement and Verification Plan** is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1, and the ISO New England Manuals.

**VAR CC Rate** is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

**VAR Payment** is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

**VAR Service** is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

**Virtual Cap** is $2,000/MWh.

**Virtual Requirements** are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

**Volt Ampere Reactive (VAR)** is a measurement of reactive power.

**Volumetric Measure (VM)** is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

**Wind High Limit** is the estimated power output (MW) of a wind Generator Asset given the Real-Time weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

**Wind Plant Future Availability** is the forecasted Real-Time High Operating Limit of a wind Generator Asset, calculated in the manner described in the ISO Operating Documents.

**Winter ARA Qualified Capacity** is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

**Winter Capability Period** means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

**Winter Intermittent Reliability Hours** are defined in Section III.13.1.2.2.2.2(c) or Section III.15.3.2.2(b) of Market Rule 1.

**Year** means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

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

**Zonal Capacity Obligation** is calculated in accordance with Section III.13.7.5.2 and Section III.15.8.5.2 of Market Rule 1.

**Zonal Reserve Requirement** is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**EXHIBIT IA**

**ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY**

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**EXHIBIT IA**

**ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY**

**Overview**

The procedures and requirements set forth in this ISO New England Financial Assurance Policy shall govern all Applicants, all Market Participants and all Non-Market Participant Transmission Customers. Capitalized terms used in the ISO New England Financial Assurance Policy shall have the meaning specified in Section I.

The purpose of the ISO New England Financial Assurance Policy is (i) to establish minimum criteria for participation in the New England Markets; (ii) to establish a financial assurance policy for Market Participants and Non-Market Participant Transmission Customers that includes commercially reasonable credit review procedures to assess the financial ability of an Applicant, a Market Participant or a Non-Market Participant Transmission Customer to pay for service transactions under the Tariff and to pay its share of the ISO expenses, including amounts under Section IV of the Tariff, and including any applicable Participant Expenses; (iii) to set forth the requirements for alternative forms of security that will be deemed acceptable to the ISO and consistent with commercial practices established by the Uniform Commercial Code that protect the ISO and the Market Participants against the risk of non-payment by other, defaulting Market Participants or by Non-Market Participant Transmission Customers; (iv) to set forth the conditions under which the ISO will conduct business in a nondiscriminatory way so as to avoid the possibility of failure of payment for services rendered under the Tariff; and (v) to collect amounts past due, to collect amounts payable upon billing adjustments, to make up shortfalls in payments, to suspend Market Participants and Non-Market Participant Transmission Customers that fail to comply with the terms of the ISO New England Financial Assurance Policy, to terminate the membership of defaulting Market Participants and to terminate service to defaulting Non-Market Participant Transmission Customers.

## I. GROUPS REGARDED AS SINGLE MARKET PARTICIPANTS

In the case of a group of Entities that are treated as a single Market Participant pursuant to Section 4.1 of the Second Restated NEPOOL Agreement (the "RNA"), the group members shall be deemed to have elected to be jointly and severally liable for all debts to Market Participants, PTOs, Non-Market Participant Transmission Customers, NEPOOL and the ISO of any of the group members. For the purposes of the ISO New England Financial Assurance Policy, the term "Market Participant" shall, in the case of a group of members that are treated as a single Market Participant pursuant to Section 4.1 of the RNA, be deemed to refer to the group of members as a whole, and any financial assurance provided

under the ISO New England Financial Assurance Policy will be credited to the account of the group member with the customer identification at the ISO.

## II. MARKET PARTICIPANTS' REVIEW AND CREDIT LIMITS

Solely for purposes of the ISO New England Financial Assurance Policy: a "Municipal Market Participant" is any Market Participant that is either (a) a Publicly Owned Entity except for an electric cooperative or an organization including one or more electric cooperatives as used in Section 1 of the RNA or (b) a municipality, an agency thereof, a body politic or a public corporation (i) that is created under the authority of any state or province that is adjacent to one of the New England states, (ii) that is authorized to own, lease and operate electric generation, transmission or distribution facilities and (iii) that has been approved for treatment as a Municipal Market Participant by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee. Market Participants that are not Municipal Market Participants are referred to as "Non-Municipal Market Participants."

### A. Minimum Criteria for Market Participation

Any entity participating or seeking to participate in the New England Markets shall comply with the requirements of this Section II.A. For purposes of this Section II.A, the term "customer" shall refer to both Market Participants and Non-Market Participant Transmission Customers and the word "applicant" shall refer to both applicants for Market Participant status and applicants for transmission service from the ISO.

#### 1. Information Disclosure

(a) Each customer and applicant, on an annual basis (by April 30 each year) shall submit a completed information form in the form of (with only minor, non-material changes) and with the information required by Attachment 6 to the ISO New England Financial Assurance Policy. Customer or applicant shall not be required to disclose information required by Attachment 6 if such disclosure is prohibited by law; provided, however, if the disclosure of any information required by Attachment 6 is prohibited by law, then customer or applicant shall use reasonable efforts to obtain permission to make such disclosure. This information shall be treated as Confidential Information, but its disclosure pursuant to subsection (b) below is expressly permitted in accordance with the terms of the ISO New England Information Policy. Customers and applicants may satisfy the requirements above by providing the ISO with filings made to the Securities

and Exchange Commission or other similar regulatory agencies that include substantially similar information to that required above, provided, however, that the customer or applicant must clearly indicate where the specific information is located in those filings. An applicant that fails to provide this information will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this information by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the information to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) The ISO will review the information provided pursuant to subsection (a) above, and will also review whether the customer or applicant or any of the Principals of the customer or applicant are included on any relevant list maintained by the U.S. Office of Foreign Asset Control. If, after review of the information provided pursuant to subsection (a) above or any other information disclosed pursuant to this Section II, the ISO in its sole discretion requires additional information to make its analysis under this subsection (b), the ISO may require additional information from the customer or applicant. If, based on these reviews, the ISO determines that the commencement or continued participation of such customer or applicant in the New England Markets may present an unreasonable risk to those markets or its Market Participants, the Chief Financial Officer of the ISO shall promptly forward to the Participants Committee or its delegate, for its input, such concerns, together with such background materials deemed by the ISO to be necessary for the Participants Committee or its delegate to develop an informed opinion with respect to the identified concerns, including any measures that the ISO may recommend imposing as a condition to the commencement or continued participation in the markets by such customer or applicant (including suspension) or the ISO's recommendation to prohibit or terminate participation by the customer or applicant in the New England Markets. The ISO shall consider the input of the Participants Committee or its delegate before taking any action to address the identified concerns. If the ISO chooses to impose measures other than prohibition (in the case of an applicant) or termination (in the case of a customer) of participation in the New England Markets, then the ISO shall be required to make an informational filing with the Commission as soon as reasonably practicable after taking such action. If the ISO chooses to prohibit (in the case of an applicant) or

terminate (in the case of a customer) participation in the New England Markets, then the ISO must file for Commission approval of such action, and the prohibition or termination shall become effective only upon final Commission ruling. No action by the ISO pursuant to this subsection (b) shall limit in any way the ISO's rights or authority under any other provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy.

**2. Risk Management**

(a) Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has: (i) either established or contracted for risk management procedures that are applicable to participation in the New England Markets; and (ii) has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) Each applicant prior to commencing activity in the FTR market shall submit to the ISO or its designee the written risk management policies, procedures, and controls, including, if requested by the ISO in its sole discretion, supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, applicable to its participation in the FTR market relied upon by the Senior Officer of the applicant signing the certificate provided pursuant to Section II.A.2 (a). On an annual basis (by April 30 each year), each Designated FTR Participant with FTR transactions in any of the previous twelve months or in any currently open month

that exceed 1,000 MW per month (on a net basis, as described in the FTR Financial Assurance Requirements provisions in Section VI) shall submit to the ISO or its designee a certificate in the form of Attachment 5 to the ISO New England Financial Assurance Policy stating that, since the customer's delivery of its risk management policies, procedures, and controls (and any supporting documentation, if applicable) or its last certificate pursuant to this Section II.A.2(b), the customer either: (i) has not made any changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable); or (ii) that changes have been made to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) and that all such changes are clearly identified and attached to such certificate. If any such applicant fails to submit the relevant written policies, procedures, and controls, then the applicant will be prohibited from participating in the FTR market. If any such customer fails to provide a certificate in the form of Attachment 5 by end of business on April 30, then the ISO shall issue a notice of such failure to the customer, and if the customer does not provide the certificate to the ISO within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions in the FTR system.

The ISO, at its sole discretion, may also require any applicant or customer to submit to the ISO or its designee the written risk management policies, procedures, and controls, including supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, that are applicable to its participation in the New England Markets relied upon by the Senior Officer of the applicant or customer signing the certificate provided pursuant to Section II.A.2(a). The ISO may require such submissions based on identified risk factors that include, but are not limited to, the markets in which the customer is transacting or the applicant seeks to transact, the magnitude of the customer's transactions or the applicant's potential transactions, or the volume of the customer's open positions. Where the ISO notifies an applicant or customer that such a submission is required, the submission shall be due within 5 Business Days of the notice. If an applicant fails to submit the relevant written policies, procedures, and controls as required, then the applicant will be prohibited from participating in the New England Markets. If a

customer fails to submit the relevant written policies, procedures, and controls, then the ISO shall issue a notice of such failure to the customer, and if the customer fails to submit the relevant written policies, procedures, and controls to the ISO or its designee within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

The applicant's or customer's written policies, procedures, controls, and any supporting documentation, received by the ISO or its designee pursuant to this subsection (b) shall be treated as Confidential Information.

(c) Where an applicant or customer submits risk management policies, procedures, and controls, or supporting documentation to the ISO or its designee pursuant to any provision of subsection (b) above, the ISO or its designee shall assess that those policies, procedures, and controls conform to prudent risk management practices, which include, but are not limited to: (i) addressing market, credit, and operational risk; (ii) segregating roles, responsibilities, and functions in the organization; (iii) establishing delegations of authority that specify which transactions traders are authorized to enter into; (iv) ensuring that traders have sufficient training in systems and the markets in which they transact; (v) placing risk limits to control exposure; (vi) requiring reports to ensure that risks are adequately communicated throughout the organization; (vii) establishing processes for independent confirmation of executed transactions; and (viii) establishing periodic valuation or mark-to-market of risk positions as appropriate.

Where, as a result of the assessment described above in this subsection (c), the ISO or its designee believes that the applicant's or customer's written policies, procedures, and controls do not conform to prudent risk management practices, then the ISO or its designee shall provide notice to the applicant or customer explaining the deficiencies. The applicant or customer shall revise its policies, procedures, and controls to address the deficiencies within 55 days after issuance of such notice. (If April 30 falls within that 55 day window, the ISO may choose not to require a separate submission on April 30 as described in subsection (b) above.) If an applicant's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the applicant will be prohibited from participating in the New England Markets. If a customer's revised written policies, procedures, and controls do not adequately address

the deficiencies identified in the notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

**3. Communications**

Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has either established or contracted to establish procedures to effectively communicate with and respond to the ISO with respect to matters relating to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy. Such procedures must ensure, at a minimum, that at least one person with the ability and authority to address matters related to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy on behalf of the customer or applicant, including the ability and authority to respond to requests for information and to arrange for additional financial assurance as necessary, is available from 9:00 a.m. to 5:00 p.m. Eastern Time on Business Days. Such procedures must also ensure that the ISO is kept informed about the current contact information (including phone numbers and e-mail addresses) for the person or people described above. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

**4. Capitalization**

(a) To be deemed as meeting the capitalization requirements, a customer or applicant shall either:

(i) be Rated and have a Governing Rating that is an Investment Grade Rating of BBB-/Baa3 or higher;

(ii) maintain a minimum Tangible Net Worth of one million dollars; or

(iii) maintain a minimum of ten million dollars in total assets, provided that, to meet this requirement, a customer or applicant may supplement total assets of less than ten million dollars with additional financial assurance in an amount equal to the difference between ten million dollars and the customer's or applicant's total assets in one of the forms described in Section X (any additional financial assurance provided pursuant to this Section II.A.4(a) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy).

(b) Any customer or applicant that fails to meet these capitalization requirements will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions of a duration greater than one month in the FTR system or any future transactions for a duration of one month or less except when FTRs for a month are being auctioned for the final time. Such a customer or applicant may enter into future transaction of a duration of one month or less in the FTR system in the case of FTRs for a month being auctioned for the final time. Any customer or applicant that fails to meet these capitalization requirements shall provide additional financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy equal to 25 percent of the customer's or applicant's FTR Financial Assurance Requirements. Any additional financial assurance provided pursuant to this Section II.A.4(b) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

(c) For markets other than the FTR market:

(i) Where a customer or applicant fails to meet the capitalization requirements, the customer or applicant will be required to provide an additional amount of financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy in an amount equal to 25 percent of the customer's or applicant's total financial assurance requirement, excluding the following:

- FTR Financial Assurance Requirements; and
- FCM Delivery Financial Assurance for customers or applicants that are assessed as medium risk or high risk per the Corporate Liquidity

Assessment (as described in Section VII.A below) from the start of the Capacity Commitment Period related to the sixteenth Forward Capacity Auction (i.e., June 1, 2025) or any Capacity Commitment Period thereafter.

(ii) An applicant that fails to provide the full amount of additional financial assurance required as described in subsection (i) above will be prohibited from participating in the New England Markets until the deficiency is rectified. For a customer, failure to provide the full amount of additional financial assurance required as described in subsection (i) above will have the same effect and will trigger the same consequences as exceeding the "100 Percent Test" as described in Section III.B.2.c of the ISO New England Financial Assurance Policy.

(iii) Any additional financial assurance provided pursuant to this Section II.A.4(c) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

**5. Additional Eligibility Requirements**

All customers and applicants shall at all times be:

(a) An "appropriate person," as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 1 *et seq.*);
(b) An "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or
(c) A "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

Each customer must demonstrate compliance with the requirements of this Section II.A.5 by submitting to the ISO on or before September 15, 2013 a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the customer is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately

cease all participation in the New England Markets. If the customer is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the customer's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the customer by a Senior Officer of the customer. A customer that fails to provide this certificate by September 15, 2013 shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

Each applicant must submit with its membership application a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the applicant is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately cease all participation in the New England Markets. If the applicant is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the applicant's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the applicant by a Senior Officer of the applicant.

The ISO, at its sole discretion, may require any applicant or customer to submit to the ISO documentation in support of the certification provided pursuant to this Section II.A.5. If at any time the ISO becomes aware that a customer no longer satisfies the requirements of this Section II.A.5, the customer shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

**6. Prior Uncured Defaults**

In addition to, and not in limitation of Section IV of the ISO New England Financial Assurance Policy, an applicant who has a previous uncured payment default must cure such payment default by payment to the ISO of all outstanding and unpaid obligations, as well as meet all requirements for participation in the New England Markets contained in the ISO New England Financial Assurance Policy. For purposes of this Section II.A.6 and the ISO's evaluation of information disclosed pursuant to Section II of the ISO New England Financial Assurance Policy, the ISO will evaluate relevant factors to determine if an entity seeking to participate in the New England Markets under a different name, affiliation, or organization, should be treated as the same customer or applicant that experienced the previous payment default. Such factors may include, but are not limited to, the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base, and the business engaged in prior to the attempted re-entry. Notwithstanding the foregoing, an applicant shall not be required to cure a payment default that has lawfully been discharged pursuant to the U.S. Bankruptcy Code.

**B. Proof of Financial Viability for Applicants**

Each Applicant must, with its membership application and at its own expense, submit proof of financial viability, as described below, satisfying the ISO requirements to demonstrate the Applicant's ability to meet its obligations. Each Applicant that intends to establish a Market Credit Limit or a Transmission Credit Limit of greater than $0 under Section II.D or Section II.E below must submit to the ISO all current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch (collectively, the "Rating Agencies"). Each Applicant, whether or not it intends to establish a Market Credit Limit or Transmission Credit Limit of greater than $0, must submit to the ISO audited financial statements for the two most recent years, or the period of its existence, if less than two years, and unaudited financial statements for its last concluded fiscal quarter if they are not included in such audited annual financial statements. These unaudited statements must be certified as to their accuracy by a Senior Officer of such Applicant, which, for purposes of ISO New England Financial Assurance Policy, means an officer of the subject entity with the title of vice president (or similar office) or higher,

or another officer designated in writing to the ISO by that officer. These audited and unaudited statements must include in each case, but are not limited to, the following information to the extent available: balance sheets, income statements, statements of cash flows and notes to financial statements, annual and quarterly reports, and 10-K, 10-Q and 8-K Reports. If any of these financial statements are available on the internet, the Applicant may provide instead a letter to the ISO stating where such statement may be located and retrieved. If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO, at the ISO's sole discretion (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; or (iii) compiled statements).

In addition, each Applicant, whether or not it intends to establish a Market Credit Limit or a Transmission Credit Limit, must submit to the ISO: (i) at least one (1) bank reference and three (3) utility company credit references, or in those cases where an Applicant does not have three (3) utility company credit references, three (3) major trade payable vendor references may be substituted; and (ii) relevant information as to any known or anticipated material lawsuits, as well as any prior bankruptcy declarations by the Applicant, or by its predecessor(s), if any; and (iii) a completed ISO credit application. In the case of certain Applicants, some of the information and documentation described in items (i) and (ii) of the immediately preceding sentence may not be applicable or available, and alternate requirements may be specified by the ISO or its designee in its sole discretion.

The ISO will not begin its review of a Market Participant's credit application or the accompanying material described above until full and final payment of that Market Participant's application fee.

The ISO shall prepare a report, or cause a report to be prepared, concerning the financial viability of each Applicant. In its review of each Applicant, the ISO or its designee shall consider all of the information and documentation described in this Section II. All costs

incurred by the ISO in its review of the financial viability of an Applicant shall be borne by such Applicant and paid at the time that such Applicant is required to pay its first annual fee under the Participants Agreement. For an Applicant applying for transmission service from the ISO, all costs incurred by the ISO shall be paid prior to the ISO's filing of a Transmission Service Agreement. The report shall be provided to the Participants Committee or its designee and the affected Applicant within three weeks of the ISO's receipt of that Applicant's completed application, application fee, and Initial Market Participant Financial Assurance Requirement, unless the ISO notifies the Applicant that more time is needed to perform additional due diligence with respect to its application.

## C. Ongoing Review and Credit Ratings

### 1. Rated and Credit Qualifying Market Participants

A Market Participant that (i) has a corporate rating from one or more of the Rating Agencies, or (ii) has senior unsecured debt that is rated by one or more of the Rating Agencies, is referred to herein as "Rated." A Market Participant that is not Rated is referred to herein as "Unrated."

For all purposes in the ISO New England Financial Assurance Policy, for a Market Participant that is Rated, 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, shall be the "Governing Rating."

A Market Participant that is: (i) Rated and whose Governing Rating is an Investment Grade Rating; or (ii) Unrated and that satisfies the Credit Threshold is referred to herein as "Credit Qualifying." A Market Participant that is not Credit Qualifying is referred to herein as "Non-Qualifying."

For purposes of the ISO New England Financial Assurance Policy, "Investment Grade Rating" for a Market Participant (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.

**2. Unrated Market Participants**

Any Unrated Market Participant that (i) has not been a Market Participant in the ISO for at least the immediately preceding 365 days; or (ii) has defaulted on any of its obligations under the Tariff (including without limitation its obligations hereunder and under the ISO New England Billing Policy) during such 365-day period; or (iii) is an FTR-Only Customer; or (iv) does not have a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 must provide an appropriate form of financial assurance as described in Section X below. An Unrated Market Participant that does not meet any of the conditions in clauses (i), (ii), (iii) and (iv) of this paragraph is referred to herein as satisfying the "Credit Threshold."

For purposes of the ISO New England Financial Assurance Policy, "Current Ratio" on any date is 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; "Debt-to-Total Capitalization Ratio" on any date is 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; and "EBITDA-to-Interest Expense Ratio" on any date is 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. The "Debt-to-Total Capitalization Ratio" will not be considered for purposes of determining whether a Municipal Market Participant satisfies the Credit Threshold. Each of the ratios described in this paragraph shall be determined in accordance with international

accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied.

**3. Information Reporting Requirements for Market Participants**

Each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis within 10 days of its becoming available and within 65 days after the end of the applicable fiscal quarter of such Market Participant, its balance sheet, which shall show sufficient detail for the ISO to assess the Market Participant's Tangible Net Worth. Unrated Market Participants having a Market Credit Limit or Transmission Credit Limit greater than zero shall also provide additional financial statements, which shall show sufficient detail for the ISO to calculate such Unrated Market Participant's Current Ratio, Debt-to-Total Capitalization Ratio and EBITDA-to-Interest Expense Ratio. In addition, each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of their becoming available and within 120 days after the end of the fiscal year of such Market Participant, balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). If any of this financial information is available on the internet, the Market Participant may provide instead a letter to the ISO stating where such information may be located and retrieved. If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; (iii) compiled statements; (iv) internally prepared statements; or (v) tax returns).

Except in the case of a Market Participant or Unrated Market Participant that submits audited financial statements to the ISO, financial statements submitted to the ISO pursuant to this Section II.C.3 shall be accompanied by a written statement from a Senior Officer of the Market Participant or Unrated Market Participant certifying the accuracy of those financial statements. If an attestation was made by an independent accounting firm, then the written statement shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required.

Notwithstanding any other provision in this subsection, the ISO may require any Market Participant to submit the financial statements and other information described in this subsection. The Market Participant shall provide the requested statements and other information within 10 days of such request. If a Market Participant fails to provide financial statements or other information as requested and the ISO determines that the Market Participant poses an unreasonable risk to the New England Markets, then the ISO may request that the Market Participant provide additional financial assurance in an amount no greater than $10 million, or take other measures to substantiate the Market Participant's ability to safely transact in the New England Markets (any additional financial assurance provided pursuant to this Section II.C.3 shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy). If the Market Participant fails to comply with such a request from the ISO, then the ISO may issue a notice of suspension or termination to the Market Participant. If the Market Participant fails to comply with the ISO's request within 5 Business Days from the date of issuance of the notice of suspension or termination, then the ISO may suspend or terminate the Market Participant.

A Market Participant may choose not to submit financial statements as described in this Section II.C.3, in which case the ISO shall use a value of $0.00 for the Market Participant's total assets and Tangible Net Worth for purposes of the capitalization assessment described in Section II.A.4(a) and such Market Participant's Market Credit Limit and Transmission Credit Limit shall be $0.00.

A Market Participant may choose to provide additional financial assurance in an amount equal to $10 million in lieu of providing financial statements under this Section II.C.3.

Such amount shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy but shall be sufficient to meet the capitalization requirements in Section II.A.4(a)(iii).

**D. Market Credit Limits**

A credit limit for a Market Participant's Financial Assurance Obligations except FTR Financial Assurance Requirements (a "Market Credit Limit") shall be established for each Market Participant in accordance with this Section II.D.

**1. Market Credit Limit for Non-Municipal Market Participants**

A "Market Credit Limit" shall be established for each Rated Non-Municipal Market Participant in accordance with subsection (a) below, and a Market Credit Limit shall be established for each Unrated Non-Municipal Market Participant in accordance with subsection (b) below.

**a. Market Credit Limit for Rated Non-Municipal Market Participants**

As reflected in the following table, the Market Credit Limit of each Rated Non-Municipal Market Participant (other than an FTR-Only Customer) shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table, (ii) $50 million, or (iii) 20 percent (20%) of 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 ("TADO").

| **Investment Grade Rating** | | **Percentage of Tangible Net Worth** |
|---|---|---|
| **S&P/Fitch** | **Moody's** | |
| AAA | Aaa | 5.50% |
| AA+ | Aa1 | 5.50% |
| AA | Aa2 | 4.50% |
| AA- | Aa3 | 4.00% |
| A+ | A1 | 3.05% |

| | | |
|---|---|---|
| A | A2 | 2.85% |
| A- | A3 | 2.60% |
| BBB+ | Baa1 | 2.30% |
| BBB | Baa2 | 1.90% |
| BBB- | Baa3 | 1.20% |
| Below BBB- | Below Baa3 | 0.00% |

An entity's "Tangible Net Worth" for purposes of the ISO New England Financial Assurance Policy on any date 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.

**b. Market Credit Limit for Unrated Non-Municipal Market Participants**

The Market Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net Worth, (ii) $25 million or (iii) 20 percent (20%) of TADO. The Market Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

**2. Market Credit Limit for Municipal Market Participants**

The Market Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to the lesser of (i) 20 percent (20%) of TADO and (ii) $25 million. The Market Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum

of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

**E. Transmission Credit Limits**

A "Transmission Credit Limit" shall be established for each Market Participant in accordance with this Section II.E, which Transmission Credit Limit shall apply in accordance with this Section II.E. A Transmission Credit Limit may not be used to meet FTR Financial Assurance Requirements.

**1. Transmission Credit Limit for Rated Non-Municipal Market Participants**

The Transmission Credit Limit of each Rated Non-Municipal Market Participant shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table or (ii) $50 million:

| **Investment Grade Rating** | | **Percentage of Tangible Net Worth** |
|---|---|---|
| **S&P/Fitch** | **Moody's** | |
| AAA | Aaa | 5.50% |
| AA+ | Aa1 | 5.50% |
| AA | Aa2 | 4.50% |
| AA- | Aa3 | 4.00% |
| A+ | A1 | 3.05% |
| A | A2 | 2.85% |
| A- | A3 | 2.60% |
| BBB+ | Baa1 | 2.30% |
| BBB | Baa2 | 1.90% |
| BBB- | Baa3 | 1.20% |
| Below BBB- | Below Baa3 | 0.00% |

**2. Transmission Credit Limit for Unrated Non-Municipal Market Participant**

The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net

Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

**3. Transmission Credit Limit for Municipal Market Participants**

The Transmission Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to $25 million. The Transmission Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

**F. Credit Limits for FTR-Only Customers**

The Market Credit Limit and Transmission Credit Limit of each FTR-Only Customer shall be $0.

**G. Total Credit Limit**

The sum of a Rated Non-Municipal Market Participant's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Municipal Market Participant that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the limit set forth in Section II.D.1.a above) and its Transmission Credit Limit (up to the limit set forth in Section II.E.1 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Municipal Market Participant may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Municipal Market Participant does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate,

or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

## III. MARKET PARTICIPANTS' REQUIREMENTS

Each Market Participant that provides the ISO with financial assurance pursuant to this Section III must provide the ISO with financial assurance in one of the forms described in Section X below and in an amount equal to the amount required in order to avoid suspension under Section III.B below (the "Market Participant Financial Assurance Requirement"). A Market Participant's Market Participant Financial Assurance Requirement shall remain in effect as provided herein until the later of (a) 150 days after termination of the Market Participant's membership or (b) the end date of all FTRs awarded to the Market Participant and the final satisfaction of all obligations of the Market Participant providing that financial assurance; provided, however that financial assurances required by the ISO New England Financial Assurance Policy related to potential billing adjustments chargeable to a terminated Market Participant shall remain in effect until such billing adjustment request is finally resolved in accordance with the provisions of the ISO New England Billing Policy. Furthermore and without limiting the generality of the foregoing, (i) any portion of any financial assurance provided under the ISO New England Financial Assurance Policy that relates to a Disputed Amount shall not be terminated or returned prior to the resolution of such dispute, even if the Market Participant providing such financial assurance is terminated or voluntarily terminates its MPSA and otherwise satisfies all of its obligations to the ISO and (ii) the ISO shall not return or permit the termination of any financial assurance provided under the ISO New England Financial Assurance Policy by a Market Participant that has terminated its membership or been terminated to the extent that the ISO determines in its reasonable discretion that that financial assurance will be required under the ISO New England Financial Assurance Policy with respect to an unsettled liability or obligation owing from that Market Participant.

A Market Participant that knows that it is not satisfying its Market Participant Financial Assurance Requirement shall notify the ISO immediately of that fact.

### A. Determination of Financial Assurance Obligations

For purposes of the ISO New England Financial Assurance Policy:

(i) a Market Participant's "Hourly Requirements" at any time will be the sum of (x) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Hourly

Charges (excluding Daily FCM Charges) for such Market Participant that have been settled but not invoiced, plus (z) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been cleared but not settled which amount shall be calculated by the Hourly Charges Estimator. The Hourly Charges Estimator (which amount shall not be less than $0) shall be determined by the following formula:

$$\text{Hourly Charges Estimator} = \sum_{i=t-n+1}^{t} HC_i \times \text{LMP ratio} \times 1.15$$

Where:

t = The last day that such Market Participant's Hourly Charges (excluding Daily FCM Charges) are fully settled;

n = The number of days that such Market Participant's Day-Ahead Energy has been cleared but not settled;

HC = The Hourly Charges (excluding Daily FCM Charges) for such Market Participant for a fully settled day; and

LMP ratio = The average Day-Ahead Prices at the New England Hub over the period of cleared but not settled n days divided by the average Day-Ahead Prices at the New England Hub over the period of most recent fully settled n days. For purposes of this Section III.A.(i), the "New England Hub" shall mean the Hub located in Western and Central Massachusetts referred to as .H.INTERNAL_HUB;

(ii) A Market Participant's "Daily FCM Requirements" at any time will be the sum of (x) the Daily FCM Charges that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Daily FCM Charges that have been settled but not invoiced, plus (z) the Daily FCM Charges for such Market Participant that have been incurred but not settled which amount shall be calculated by the Daily FCM Obligation Estimator. The Daily FCM Obligation Estimator (which amount shall not be less than $0) shall be determined by the following formula:

Daily FCM Obligation Estimator = MAX(FCM_Daily_Credit_CM x NDAY_CM + FCM_Daily_Credit_PM x NDAY_PM + FCM_Charge_LD x NDAY_P2 x FCA_Price_Ratio, 0)

Where:

FCM_Daily_Credit_CM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the current month;

FCM_Daily_Credit_PM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the month preceding the current month;

NDAY_CM is the number of days in the current month within the period from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

NDAY_PM is the number of days in the month preceding the current month within the period from the last day of the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

FCM_Charge_LD is the portion of the Daily FCM Charges that corresponds to Capacity Load Obligations for the Market Participant from the last day the Daily FCM Charges have been settled; and

NDAY_P2 is the number of days from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed) plus 2.

The FCA_Price_Ratio shall be calculated as the weighted average of the Capacity Clearing Prices for the Rest-of-Pool Capacity Zone for the relevant Capacity Commitment Periods divided by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day the Daily FCM Charges have been settled, as determined by the following formula:

$$FCA\_Price\_Ratio = (((Clearing\ Price\_CCP_n \times NDAY\_P2\_CCP_n) + (Clearing\ Price\_CCP_{n+1} \times NDAY\_P2\_CCP_{n+1}))/NDAY\_P2)/(Clearing\ Price\_CCP_n)$$

Where:

Clearing Price_$CCP_n$ is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day that the Daily FCM Charges have been settled;

Clearing Price_$CCP_{n+1}$ is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone for the Capacity Commitment Period following $CCP_n$;

NDAY_P2_$CCP_n$ is number of days in the $CCP_n$ within NDAY_P2; and

NDAY_P2_$CCP_{n+1}$ is number of days in the $CCP_{n+1}$ within NDAY_P2.

(iii) a Market Participant's "Non-Hourly Requirements" at any time will be determined by averaging that Market Participant's Non-Hourly Charges but not include: (A) the amount due from or to such Market Participant for FTR transactions, (B) any amounts due from such Market Participant for the Forward Capacity Market, (C) any amounts due under Section 14.1 of the RNA, (D) any amounts due for NEPOOL GIS API Fees, and (E) the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Market Participant) over the two most recently invoiced calendar months; provided that such Non-Hourly Requirements shall in no event be less than zero;

(iv) a Market Participant's "Transmission Requirements" at any time will be determined by averaging that Market Participant's Transmission Charges over the two most recently invoiced calendar months; provided that such Transmission Requirements shall in no event be less than $0;

(v) a Market Participant's Virtual Requirements at any time will equal the amount of all unsettled Increment Offers and Decrement Bids submitted by such Market Participant at such time (which amount of unsettled Increment Offers and Decrement Bids will be calculated by the ISO according to a methodology approved from time to time by the NEPOOL Budget and Finance Subcommittee and posted on the ISO's website);

(vi) a Market Participant's "Financial Assurance Obligations" at any time will be equal to the sum at such time of:

a. such Market Participant's Hourly Requirements; plus
b. such Market Participant's Daily FCM Requirements; plus
c. such Market Participant's Virtual Requirements; plus
d. such Market Participant's Non-Hourly Requirements times 2.50 (subject to Section X.D with respect to Provisional Members); plus
e. such Market Participant's "FTR Financial Assurance Requirements" under Section VI below; plus
f. such Market Participant's "FCM Financial Assurance Requirements" under Section VII below; plus

g. such Market Participant's "IEP Financial Assurance Requirement" under Section III.D below; plus

h. the amount of any Disputed Amounts received by such Market Participant; and

(vii) a Market Participant's "Transmission Obligations" at any time will be such Market Participant's Transmission Requirements times 2.50.

To the extent that the calculations of the components of a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) as described above produce positive and negative values, such components may offset each other; provided, however, that a Market Participant's Financial Assurance Obligations shall never be less than zero.

## B. Credit Test Calculations and Allocation of Financial Assurance, Notice and Suspension from the New England Markets

### 1. Credit Test Calculations and Allocation of Financial Assurance

The financial assurance provided by a Market Participant shall be applied as described in this Section.

(a) "Market Credit Test Percentage" is equal to a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) divided by the sum of its Market Credit Limit and any financial assurance allocated as described in subsection (d) below.

(b) "FTR Credit Test Percentage" is equal to a Market Participant's FTR Financial Assurance Requirements divided by any financial assurance allocated as described in subsection (d) below.

(c) "Transmission Credit Test Percentage" is equal to a Market Participant's Transmission Obligations divided by the sum of its Transmission Credit Limit and any financial assurance allocated as described in subsection (d) below.

(d) A Market Participant's financial assurance shall be allocated as follows:

(i) financial assurance shall be first allocated so as to ensure that the Market Participant's Market Credit Test Percentage is no greater that 100%;

(ii) any financial assurance that remains after the allocation described in subsection (d) (i) shall be allocated so as to ensure that the Market Participant's FTR Credit Test Percentage is no greater than 100%;

(iii) any financial assurance that remains after the allocation described in subsection (d) (ii) shall be allocated so as to ensure that the Market Participant's Transmission Credit Test Percentage is no greater than 100%;

(iv) if any financial assurance remains after the allocations described in subsection (d) (iii), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 89.99%;

(v) if any financial assurance remains after the allocation described in subsection (d) (iv), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 79.99%;

(vi) any financial assurance that remains after the allocations described in subsection (d) (v) shall be allocated to the Market Credit Test Percentage.

**2. Notices**

**a. 80 Percent Test**

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant.

**b. 90 Percent Test**

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) , then, in addition to the actions to be taken when the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant. The ISO shall also issue a 90 percent (90%) notice to a Market Participant and take certain other actions under the circumstances described in Section III.B.2.c below.

**c. 100 Percent Test**

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or when the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equal zero, then, in addition to the actions to be taken when the

Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%) and 90 percent (90%), (i) the ISO shall issue notice thereof to such Market Participant, (ii) that Market Participant shall be immediately suspended from submitting Increment Offers and Decrement Bids until such time when its Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are less than or equal to 100 percent (100%), and (iii) if sufficient financial assurance to lower the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 100 percent (100%) or, in the case of a Market Participant that has received one to five notices that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) in the previous 365 days (not including the instant notice), sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%), is not provided by 8:30 a.m. Eastern Time on the next Business Day, (a) the event shall be a Financial Assurance Default; (b) the ISO shall issue notice thereof to such Market Participant, to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contacts for all Market Participants, and (c) such Market Participant shall be suspended from: (1) the New England Markets, as provided below; (2) receiving transmission service under any existing or pending arrangements under the Tariff or scheduling any future transmission service under the Tariff; (3) voting on matters before the Participants Committee and NEPOOL Technical Committees; (4) entering into any future transactions in the FTR system; and (5) submitting an offer of Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction in the Forward Capacity Market, in each case until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 100 percent (100%) or less. In addition to all of the provisions above, any Market Participant that has received six or more notices in the previous 365 days that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) shall receive a notice thereof and shall be required to maintain sufficient financial assurance to keep such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage at less than or equal to 90

percent (90%). If such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage exceeds 90 percent (90%), the ISO shall issue a notice thereof to such Market Participant. If sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%) is not provided by 8:30 a.m. Eastern Time on the next Business Day, then the consequences described in subsections (a), (b) and (c) of Section III.B.2.c (iii) above shall apply until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 90 percent (90%) or less.

However, when a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or 90 percent (90%), as applicable under this Section III.B.2.c, solely because its Investment Grade Rating is downgraded by one grade and the resulting grade is BBB-/Baa3 or higher, then (x) for five Business Days after such downgrade, such downgrade shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage and (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such downgrade if such Market Participant cures such default within such five Business Day period. When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent solely because a letter of credit is valued at $0 prior to the termination of that letter of credit, as described in Section X.B, then the ISO, in its sole discretion, may determine that: (x) for five Business Days after such change in the valuation of the letter of credit, such valuation shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage; and/or (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such valuation if such Market Participant cures such default within such five Business Day period.

Notwithstanding the foregoing, a Market Participant shall neither (x) receive a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) nor (y) be suspended under this Section

III.B if (i) the amount of financial assurance necessary for that Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to get to 100 percent (100%) or lower is less than $1,000 or (ii) that Market Participant's status with the ISO has been terminated.

**3. Suspension from the New England Markets**

**a. General**

The suspension of a Market Participant, and any resulting annulment, termination or removal of OASIS reservations, removal from the settlement system and the FTR system, suspension of the ability to offer Non-Commercial Capacity or participate in a substitution auction in the Forward Capacity Market, drawing down of financial assurance, rejection of Increment Offers and Decrement Bids, and rejection of bilateral transactions submitted to the ISO, shall not limit, in any way, the ISO's right to invoice or collect payment for any amounts owed (whether such amounts are due or becoming due) by such suspended Market Participant under the Tariff or the ISO's right to administratively submit a bid or offer of a Market Participant's Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction or to make other adjustments under Market Rule 1.

In addition to the notices provided herein, the ISO will provide any additional information required under the ISO New England Information Policy.

Each notice issued by the ISO pursuant to this Section III.B shall indicate whether the subject Market Participant has a registered load asset. If the ISO has issued a notice pursuant to this Section III.B and subsequently the subject Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%), such Market Participant may request the ISO to issue a notice stating such fact. However, the ISO shall not be obligated to issue such a notice unless, in its sole discretion, the ISO concludes that such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%).

Notwithstanding the foregoing, if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will not be issued.

If a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will be issued only to such Market Participant, and such Market Participant shall be "suspended" as described below.

Any such suspension as a result of one or more Increment Offers or Decrement Bids submitted by a Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, shall take effect immediately upon submission of such Increment Offers and/or Decrement Bids or such bilateral transactions to remain in effect until such Market Participant is in compliance with the ISO New England Financial Assurance Policy, notwithstanding any provision of this Section III.B to the contrary.

If a Market Participant is suspended from the New England Markets in accordance with the provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy, then the provisions of this Section III.B shall control notwithstanding any other provision of the Tariff to the contrary. A suspended Market Participant shall have no ability so long as it is suspended (i) to be reflected in the ISO's settlement system, including any bilateral transactions, as either a purchaser or a seller of any products or services sold through the New England Markets (other than (A) Commercial Capacity and (B) Non-Commercial Capacity during the Non-Commercial

Capacity Cure Period) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the Market Participants, (ii) to submit Demand Bids, Decrement Bids or Increment Offers in the New England Markets, (iii) to submit offers for Non-Commercial Capacity in any Forward Capacity Auction or reconfiguration auction or acquire Non-Commercial Capacity through a Capacity Supply Obligation Bilateral, or (iv) to submit supply offers or demand bids in any Forward Capacity Market substitution auction. Any transactions, including bilateral transactions with a suspended Market Participant (other than transactions for (A) Commercial Capacity and (B) Non-Commercial Capacity during the Non-Commercial Capacity Cure Period) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the other Market Participants and any Demand Bids, Decrement Bids, Increment Offers, and Export Transactions submitted by a suspended Market Participant shall be deemed to be terminated for purposes of the Day-Ahead Energy Market clearing and the ISO's settlement system. If a Market Participant has provided the financial assurance required for a Capacity Supply Obligation Bilateral or Annual Reconfiguration Transaction, then that Capacity Supply Obligation Bilateral or Annual Reconfiguration Transaction, respectively, will not be deemed to be terminated when that Market Participant is suspended.

**b. Load Assets**

Any load asset registered to a suspended Market Participant shall be terminated, and the obligation to serve the load associated with such load asset shall be assigned to the relevant unmetered load asset(s) unless and until the host Market Participant for such load assigns the obligation to serve such load to another asset. If the suspended Market Participant is responsible for serving an unmetered load asset, such suspended Market Participant shall retain the obligation to serve such unmetered load asset. If a suspended Market Participant has an ownership share of a load asset, such ownership share shall revert to the Market Participant that assigned such ownership share to such suspended Market Participant. If a suspended Market Participant has the obligation under the Tariff or otherwise to offer any of its supply or to bid any pumping load to provide products or services sold through the New England Markets, that obligation shall continue, but only in Real-Time, notwithstanding the Market Participant's suspension, and such offer or bid, if cleared under the Tariff, shall be effective.

**c. FTRs**

If a Market Participant is suspended from entering into future transactions in the FTR system, such Market Participant shall retain all FTRs held by it but shall be prohibited from acquiring any additional FTRs during the course of its suspension. It is intended that any suspension under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy will occur promptly, and the definitive timing of any such suspension shall be determined by the ISO from time to time as reported to the NEPOOL Budget and Finance Subcommittee, and shall be posted on the ISO website.

**d. Virtual Transactions**

Notwithstanding the foregoing, if a Market Participant is suspended in accordance with the provisions of the ISO New England Financial Assurance Policy as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant and, but for such Increment Offers and/or Decrement Bids, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, then such suspension shall be limited to (i) the immediate "last in, first out" rejection of pending individual uncleared Increment Offers and Decrement Bids submitted by that Market Participant (it being understood that Increment Offers and Decrement Bids are batched by the ISO in accordance with the time, and that Increment Offers and Decrement Bids will be rejected by the batch); and (ii) the suspension of that Market Participant's ability to submit additional Increment Offers and Decrement Bids unless and until it has complied with the ISO New England Financial Assurance Policy, and the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of that Market Participant after giving effect to the immediate rejection of that Market Participant's Increment Offers and Decrement Bids described in clause (i).

**e. Bilateral Transactions**

If the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equals zero and that Market Participant would be in compliance with the ISO New England Financial Assurance Policy but for the submission of bilateral transactions to the ISO to which the Market Participant is a party, or if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent as a result of one or more bilateral transactions submitted to the ISO to which the Market Participant is a party, then the consequences described in subsection (a) above shall be limited to: (i) rejection of any pending bilateral transactions to which a Market Participant is a party that cause the Market Participant to incur a financial obligation in the ISO's settlement system or any

liability to the ISO, NEPOOL, or the Market Participants, such that the aggregate value of the pending bilateral transactions submitted by all Market Participants is maximized (recognizing the downstream effect that rejection of a bilateral transaction may have on the Market Credit Test Percentages, FTR Credit Test Percentages, or Transmission Credit Test Percentages of other Market Participants), while ensuring that the financial assurance requirements of each Market Participant are satisfied; and (ii) suspension of that Market Participant's ability to submit additional bilateral transactions until it has complied with the ISO New England Financial Assurance Policy (the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of the Market Participant after giving effect to the immediate rejection of the bilateral transactions to which the Market Participant is a party as described in clause (i) above). In the case of a bilateral transaction associated with the Day-Ahead Energy Market, the ISO will provide notice to a Market Participant that would be in default of the ISO New England Financial Assurance Policy as a result of the bilateral transaction, and the consequences described in clauses (i) and (ii) above shall only apply if the Market Participant fails to cure its default by 6:00 p.m. Eastern Time of that same Business Day. In the case of a Capacity Load Obligation Bilateral, the consequences described in clauses (i) and (ii) above shall apply if the Market Participant does not cure its default within one Business Day after notification that a Capacity Load Obligation Bilateral caused the default. Bilateral transactions that transfer Forward Reserve Obligations and Supplemental Availability Bilaterals are not subject to the provisions of this Section III.B.3(e).

**4. Serial Notice and Suspension Penalties**

If either (x) a Market Participant is suspended from the New England Markets because of a failure to satisfy its Financial Assurance Requirements in accordance with the provisions of the ISO New England Financial Assurance Policy or (y) a Market Participant receives more than five notices that its Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage has exceeded 100 percent (100%) in any rolling 365-day period, then such Market Participant shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 365-day period. If a Market Participant receives a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) in the same day, then only one of those notices will count towards the

five notice limit. All penalties paid under this paragraph shall be deposited in the Late Payment Account maintained under the ISO New England Billing Policy.

**C. Additional Financial Assurance Requirements for Certain Municipal Market Participants**

Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, a Credit Qualifying Municipal Market Participant that is not a municipality (which, for purposes of this Section III.C, does not include an agency or subdivision of a municipality) must provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation, unless either: (1) that Credit Qualifying Municipal Market Participant has a corporate Investment Grade Rating from one or more of the Rating Agencies; or (2) that Credit Qualifying Municipal Market Participant has an Investment Grade Rating from one or more of the Rating Agencies for all of its rated indebtedness; or (3) that Credit Qualifying Municipal Market Participant provides the ISO with an opinion of counsel that is acceptable to the ISO confirming that amounts due to the ISO under the Tariff have priority over, or have equal priority with, payments due on the debt on which the Credit Qualifying Municipal Market Participant's Investment Grade Rating is based. Each legal opinion provided under clause (3) of this Section III.C will be updated no sooner than 60 days and no later than 30 days before each reconfiguration auction that precedes a Capacity Commitment Period to which such legal opinion relates, and if that update is not provided or that update is not acceptable to the ISO, the applicable Credit Qualifying Municipal Market Participant must either satisfy one of the other clauses of this Section III.C or provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation.

**D. Inventoried Energy Program Financial Assurance Requirement**

Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, if any Market Participant has submitted a Forward Energy Inventory Election approved by the ISO under Section III.K.1.1 of the Tariff, such Market Participant shall be subject to the additional financial assurance requirements of this section. Any such Market Participant must provide additional financial assurance in one of the forms described in Section X below in an

amount equal to the Inventoried Energy Program Financial Assurance Requirement on or before December 1 of each program year. The Inventoried Energy Program Financial Assurance Requirement will be calculated on a daily basis for each program year, from December 1, 2023 through February 29, 2024 and separately from December 1, 2024 through February 28, 2025, as follows:

IEP Financial Assurance Requirement = MAX(0, FE_MWh - Q_MWh) * D_95 * MF * SPR

Where:

FE_MWh = is the amount of Forward Energy Inventory elected by the Market Participant;

Q_MWh = is the maximum observed physical inventory over the prior 15 days;

D_95 = is the 95th percentile of observed Inventoried Energy Days, which for the 2023-2024 and 2024-2025 program years shall be 19;

MF = is the month factor, which shall be 100% for December, 87% for January, and 26% for February; and

SPR = spot payment rate = the $/MWh rate used in the calculation of Inventoried Energy Spot Payments as described in Section III.K.3.2 of the Tariff.

## IV. CERTAIN NEW AND RETURNING MARKET PARTICIPANTS REQUIREMENTS

A new Market Participant or 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 (a "Returning Market Participant") is required to provide the ISO, for three months in the case of a new Market Participant and six months in the case of a Returning Market Participant, financial assurance in one of the forms described in Section X below equal to any amount of additional financial assurance required to meet the capitalization requirements described in Section II.A.4 plus the greater of (a) its Financial Assurance Requirement or (b) its "Initial Market Participant Financial Assurance Requirement." A new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement must be provided to the ISO no later than one Business Day before commencing activity in the New England Markets or commencing transmission service under the Tariff, and shall be determined by the following formula:

$$FAR = G + T + L + E$$

Where FAR is the Initial Market Participant Financial Assurance Requirement and G, T, L and E are determined by the following formulas:

$G = (MW_g \times Hr_{DA} \times D \times 3.25) + (MW_g \times Hr_{MIS} \times S_2 \times 3.25)$;

Where:

$MW_g$ = Total nameplate capacity of the Market Participant's generation units that have achieved commercial operation;

$Hr_{DA}$ = The number of hours of generation that any such generation unit could be bid in the Day-Ahead Energy Market before it could be removed if such unit tripped, as determined by the ISO in its sole discretion;

D = The maximum observed differential between Energy prices in the Day-Ahead and Real-Time Energy Markets during the prior calendar year ("Maximum Energy Price Differential"), as determined by the ISO in its sole discretion;

$Hr_{MIS}$ = The standard number of hours between generation and the issuance of initial Market Information Server ("MIS") settlement reports including projected generation activity for such units, as determined by the ISO in its sole discretion; and

$S_2$ = The per MW amount assessed pursuant to Schedule 2 of Section IV.A of this Tariff, as determined by the ISO.

T = $MW_t \times Hr_{MIS} \times (D + S_{2\text{-}3}) \times 3.25$;

Where: $MW_t$ = Number of MWs to be traded in the New England Markets as reasonably projected by the new Market Participant or the Returning Market Participant;

$Hr_{MIS}$ = The standard number of hours between generation and the issuance of initial MIS settlement reports including projected generation activity, as determined by the ISO in its sole discretion;

D = Maximum Energy Price Differential; and

$S_{2-3}$ = The per MWh amount assessed pursuant to Schedules 2 and 3 of Section IV.A of the Tariff, as determined annually by the ISO.

$$L = (MW_1 \times LF \times Hr_{MIS} \times (EP + S_{2-3}) \times 3.25) + (MW_1 \times Hr_{MIS} \times TC \times 3.25)$$

Where:

$MW_1$ = MWs of Real-Time Load Obligation (as defined in Market Rule 1) of the new Market Participant or Returning Market Participant;

LF = Average load factor in New England, as determined annually by the ISO in its sole discretion;

$Hr_{MIS}$ = The standard number of hours between generation and the issuance of initial MIS settlement reports including projected generation activity, as determined by the ISO in its sole discretion;

EP = The average price of Energy in the Day-Ahead Energy Market for the most recent calendar year for which information is available from the Annual Reports published by the ISO, as determined by the ISO in its sole discretion;

$S_{2-3}$ = The per MW amount assessed pursuant to Schedules 2 and 3 of Section IV.A of the Tariff, as determined annually by the ISO; and

TC = The hourly transmission charges per $MW_1$ assessed under the Tariff (other than Schedules 1, 8 and 9 of Section II of the Tariff), as determined annually by the ISO.

$$E = (SE) \times 3.25$$

Where:

SE = Average monthly share of Participant Expenses for the applicable Sector.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV is 80 percent or more of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equaled or exceeded 80 percent (80%) under Section III.B above.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV is 90 percent or more of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equaled or exceeded 90 percent (90%) under Section III.B above.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV exceeds 100 percent of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeded 100 percent (100%) under Section III.B above.

## V. NON-MARKET PARTICIPANT TRANSMISSION CUSTOMERS REQUIREMENTS

### A. Ongoing Financial Review and Credit Ratings

#### 1. Rated Non-Market Participant Transmission Customer and Transmission Customers

Each Rated Non-Market Participant Transmission Customer that does not currently have an Investment Grade Rating must provide an appropriate form of financial assurance as described in Section X below.

**2. Unrated Non-Market Participant Transmission Customers**

Any Unrated Non-Market Participant Transmission Customer that (i) has defaulted on any of its obligations under the Tariff (including without limitation its obligations hereunder and under the ISO New England Billing Policy) during the immediately preceding 365-day period; or (ii) does not have a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 must provide an appropriate form of financial assurance as described in Section X below. An Unrated Non-Market Participant Transmission Customer that does not meet either of the conditions described in clauses (i) and (ii) of this paragraph is referred to herein as satisfying the "NMPTC Credit Threshold."

**B. NMPTC Credit Limits**

**1. NMPTC Market Credit Limit**

A Market Credit Limit shall be established for each Non-Market Participant Transmission Customer as set forth in this Section V.B.1.

The Market Credit Limit of each Rated Non-Market Participant Transmission Customer shall at any time be equal to the least of: (i) the applicable percentage of such Rated Non-Market Participant Transmission Customer's Tangible Net Worth (as reflected in the following table); (ii) $50 million; or (iii) 20 percent (20%) of TADO:

| **Investment Grade Rating** | | **Percentage of Tangible Net Worth** |
|---|---|---|
| **S&P/Fitch** | **Moody's** | |
| AAA | Aaa | 5.50% |
| AA+ | Aa1 | 5.50% |
| AA | Aa2 | 4.50% |
| AA- | Aa3 | 4.00% |
| A+ | A1 | 3.05% |

| | | |
|---|---|---|
| A | A2 | 2.85% |
| A- | A3 | 2.60% |
| BBB+ | Baa1 | 2.30% |
| BBB | Baa2 | 1.90% |
| BBB- | Baa3 | 1.20% |
| Below BBB- | Below Baa3 | 0.00% |

The Market Credit Limit of each Unrated Non-Market Participant Transmission Customer that satisfies the NMPTC Credit Threshold shall at any time be equal to the least of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Market Participant Transmission Customer's Tangible Net Worth, (ii) $25 million or (iii) 20 percent (20%) of TADO. The Market Credit Limit of each Unrated Non-Market Participant Transmission Customer that does not satisfy the NMPTC Credit Threshold shall be $0.

**2. NMPTC Transmission Credit Limit**

A Transmission Credit Limit shall be established for each Non-Market Participant Transmission Customer in accordance with this Section V.B.2.

The Transmission Credit Limit of each Rated Non-Market Participant Transmission Customer shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Market Participant Transmission Customer's Tangible Net Worth as listed in the following table or (ii) $50 million:

| **Investment Grade Rating** | | **Percentage of Tangible Net Worth** |
|---|---|---|
| **S&P/Fitch** | **Moody's** | |
| AAA | Aaa | 5.50% |
| AA+ | Aa1 | 5.50% |
| AA | Aa2 | 4.50% |
| AA- | Aa3 | 4.00% |
| A+ | A1 | 3.05% |
| A | A2 | 2.85% |
| A- | A3 | 2.60% |
| BBB+ | Baa1 | 2.30% |
| BBB | Baa2 | 1.90% |

| | | |
|---|---|---|
| BBB- | Baa3 | 1.20% |
| Below BBB- | Below Baa3 | 0.00% |

The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that satisfies the NMPTC Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Market Participant Transmission Customer's Tangible Net Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that does not satisfy the NMPTC Credit Threshold shall be $0.

**3. NMPTC Total Credit Limit**

The sum of a Non-Market Participant Transmission Customer's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Market Participant Transmission Customer that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the amount set forth in Section V.B.1 above) and its Transmission Credit Limit (up to the amount set forth in Section V.B.2 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Market Participant Transmission Customer may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Market Participant Transmission Customer does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate, or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

**C. Information Reporting Requirements for Non-Market Participant Transmission Customers**

Each Rated Non-Market Participant Transmission Customer having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis, within 10 days of their becoming available and within 65 days after the end of the applicable fiscal quarter of such Rated Non-Market Participant Transmission Customer, its balance sheet, which shall show sufficient detail for the ISO to assess the Rated Non-Market Participant Transmission Customer's Tangible Net Worth. In addition, each Rated Non-Market Participant Transmission Customer that has an Investment Grade Rating having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of their becoming available and within 120 days after the end of the fiscal year of such Rated Non-Market Participant Transmission Customer, balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). If any of this financial information is available on the internet, the Rated Non-Market Participant Transmission Customer may provide instead a letter to the ISO stating where such information may be located and retrieved.

Each Unrated Non-Market Participant Transmission Customer having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis, within 10 days of their becoming available and within 65 days after the end of the applicable fiscal quarter of such Unrated Non-Market Participant Transmission Customer, its balance sheet, which shall show sufficient detail for the ISO to assess the Unrated Non-Market Participant Transmission Customer's Tangible Net Worth. Unrated Non-Market Participant Transmission Customers having a Market Credit Limit or Transmission Credit Limit greater than $0 shall also provide additional financial statements, which shall show

sufficient detail for the ISO to calculate such Unrated Non-Market Participant Transmission Customer's Current Ratio, Debt-to-Total Capitalization Ratio and EBITDA-to-Interest Expense Ratio. In addition, each such Unrated Non-Market Participant Transmission Customer that satisfies the Credit Threshold and has a Market Credit Limit or Transmission Credit Limit of greater than $0 or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of becoming available and within 120 days after the end of the fiscal year of such Unrated Non-Market Participant Transmission Customer balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). Where any of the above financial information is available on the internet, the Unrated Non-Market Participant Transmission Customer may provide the ISO with a letter stating where such information may be located and retrieved.

If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-along subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; (iii) compiled statements; (iv) internally prepared statements; or (v) tax returns).

Except in the case of a Non-Market Participant Transmission Customer that submits audited financial statements to the ISO, financial statements submitted to the ISO pursuant to this Section V.C shall be accompanied by a written statement from a Senior Officer of the Non-Market Participant Transmission Customer certifying the accuracy of those financial statements. If an attestation was made by an independent accounting firm, then the written statement shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required.

Notwithstanding any other provision in this subsection, the ISO may require any Non-Market Participant Transmission Customer to submit the financial statements and other information described in this subsection. The Non-Market Participant Transmission Customer shall provide the requested statements and other information within 10 days of such request. If a Non-Market Participant Transmission Customer fails to provide financial statements or other information as requested and the ISO determines that the Non-Market Participant Transmission Customer poses an unreasonable risk to the New England Markets, then the ISO may request that the Non-Market Participant Transmission Customer provide additional financial assurance in an amount no greater than $10 million, or take other measures to substantiate the Non-Market Participant Transmission Customer's ability to safely transact in the New England Markets (any additional financial assurance provided pursuant to this Section V.C shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy). If the Non-Market Participant Transmission Customer fails to comply with such a request from the ISO, then the ISO may issue a notice of suspension or termination to the Non-Market Participant Transmission Customer. If the Non-Market Participant Transmission Customer fails to comply with the ISO's request within 5 Business Days from the date of issuance of the notice of suspension or termination, then the ISO may suspend or terminate the Non-Market Participant Transmission Customer.

A Non-Market Participant Transmission Customer may choose not to submit financial statements as described in this Section V.C, in which case the ISO shall use a value of $0.00 for the Non-Market Participant Transmission Customer's total assets and Tangible Net Worth for purposes of the capitalization assessment described in Section II.A.4(a) and such Non-Market Participant Transmission Customer's Market Credit Limit and Transmission Credit Limit shall be $0.00.

A Non-Market Participant Transmission Customer may choose to provide additional financial assurance in an amount equal to $10 million in lieu of providing financial statements under this Section V.C. Such amount shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy but shall be sufficient to meet the capitalization requirements in Section II.A.4(a)(iii).

**D. Financial Assurance Requirement for Non-Market Participant Transmission Customers**

Each Non-Market Participant Transmission Customer that provides additional financial assurance pursuant to the ISO New England Financial Assurance Policy must provide the ISO with financial assurance in one of the forms described in Section X below and in the amount described in this Section V.D (the "NMPTC Financial Assurance Requirement").

**1. Financial Assurance for ISO Charges**

Each Non-Market Participant Transmission Customer must provide the ISO with additional financial assurance such that the sum of its Market Credit Limit and that additional financial assurance shall at all times be at least equal to the sum of:

(i) two and one-half (2.5) times the average monthly Non-Hourly Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0); plus

(ii) amount of any unresolved Disputed Amounts received by such Non-Market Participant Transmission Customer.

**2. Financial Assurance for Transmission Charges**

Each Non-Market Participant Transmission Customer must provide the ISO with additional financial assurance hereunder such that the sum of (x) its Transmission Credit Limit and (y) the excess of (A) the available amount of the additional financial assurance provided by that Non-Market Participant Transmission Customer over (B) the amount of that additional financial assurance needed to satisfy the requirements of Section V.D.1 above is equal to two and one-half (2.5) times the average monthly Transmission Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0)

**3. Notice of Failure to Satisfy NMPTC Financial Assurance Requirement**

A Non-Market Participant Transmission Customer that knows or can reasonably be expected to know that it is not satisfying its NMPTC Financial Assurance Requirement shall notify the ISO immediately of that fact. Without limiting the availability of any other remedy or right hereunder, failure by any Non-Market Participant Transmission

Customer to comply with the provisions of the ISO New England Financial Assurance Policy (including failure to satisfy its NMPTC Financial Assurance Requirement) may result in the commencement of termination of service proceedings against that non-complying Non-Market Participant Transmission Customer.

## VI. ADDITIONAL PROVISIONS FOR FTR TRANSACTIONS

Market Participants must complete an ISO-prescribed training course prior to participating in the FTR Auction. All Market Participants transacting in the FTR Auction that are otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, including all FTR-Only Customers ("Designated FTR Participants") are required to provide financial assurance in an amount equal to the sum of the FTR Settlement Risk Financial Assurance, the Unsettled FTR Financial Assurance, and the Settlement Financial Assurance, each as described in this Section VI (such sum being referred to in the ISO New England Financial Assurance Policy as the "FTR Financial Assurance Requirements").

### A. FTR Settlement Risk Financial Assurance

A Designated FTR Participant is required to provide "FTR Settlement Risk Financial Assurance" for each bid it submits into an FTR Auction and for each FTR that is awarded to it in an FTR Auction, as described below.

After bids are finalized for an FTR Auction, but before the auction results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on its bids for each FTR path. The ISO will calculate an FTR Settlement Risk Financial Assurance amount for each direction (prevailing flow and counter flow) of each FTR path on which the Designated FTR Participant has bid, equal to the total number of MW bid for that direction of the FTR path multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the bid. For that FTR path, the Designated FTR Participant must provide FTR Settlement Risk Financial Assurance equal to the higher of the amounts calculated for each direction.

Once an FTR Auction's results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on awarded FTRs, equal to the MW value of each awarded FTR multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the FTR. For

purposes of this calculation, the ISO will net the MW values of a Designated FTR Participant's awarded FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak). For purposes of this netting, annual FTRs may be converted into monthly positions.

The proxy value for each FTR path, which shall be calculated separately for on-peak and off-peak FTRs, will be based on the standard deviation observed in the difference between the average congestion components of the Locational Marginal Price in the Day-Ahead Energy Market at the path's sink and source for the previous 36 months, with differing multipliers for annual and monthly FTRs and for prevailing flow and counter flow paths. These multipliers will be reviewed and approved by the NEPOOL Budget and Finance Subcommittee and shall be posted on the ISO's website. Where there is insufficient data to perform these calculations for a node, zonal data will be used instead.

FTR Settlement Risk Financial Assurance will be adjusted as the awarded FTRs are settled. In no event will the FTR Settlement Risk Financial Assurance be less than $0.

**B. Unsettled FTR Financial Assurance**

A Designated FTR Participant is required to maintain, at all times, "Unsettled FTR Financial Assurance" for all FTRs awarded to it in any FTR Auctions. Immediately after FTRs are awarded in an FTR Auction, the Unsettled FTR Financial Assurance for those FTRs shall be zero. After subsequent FTR Auctions, the Unsettled FTR Financial Assurance for each FTR awarded in a previous FTR Auction shall be adjusted to reflect any change in the clearing price for that FTR based on non-zero volume. The adjustment will be equal to the change in the clearing price multiplied by the number of MW of the previously awarded FTR, with increases in the clearing price reducing the Unsettled FTR Financial Assurance amount and decreases in the clearing price increasing the Unsettled FTR Financial Assurance amount. For purposes of these calculations, the ISO will consider FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak) together. A Designated FTR Participant's Unsettled FTR Financial Assurance may be a charge or a credit, and in the case of a credit, may offset the Designated FTR Participant's other FTR Financial Assurance Requirements (but not to less than zero). A Designated FTR Participant's Unsettled FTR Financial Assurance will be adjusted as the awarded FTRs are settled.

**C. Settlement Financial Assurance**

A Designated FTR Participant that has been awarded a bid in an FTR Auction is required to provide "Settlement Financial Assurance." The amount of a Designated FTR Participant's Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement. Additionally, when the Designated FTR Participant is invoiced and the net of the charges incurred by such Designated FTR Participant for FTR transactions and the amount due to such Market Participant for FTR transactions results in a net charge, the amount of the net charge shall be added to the Designated FTR Participant's Settlement Financial Assurance until the invoice is paid.

**D. Consequences of Failure to Satisfy FTR Financial Assurance Requirements**

If a Designated FTR Participant does not have additional financial assurance equal to its FTR Financial Assurance Requirements (in addition to its other financial assurance obligations hereunder) in place at the time an FTR Auction into which it has bid closes, then, in addition to the other consequences described in the ISO New England Financial Assurance Policy, all bids submitted by that Designated FTR Participant for that FTR Auction will be rejected. The Designated FTR Participant will be allowed to participate in the next FTR Auction held provided it meets all requirements for such participation, including without limitation those set forth herein. Each Designated FTR Participant must maintain the requisite additional financial assurance equal to its FTR Financial Assurance Requirements for the duration of the FTRs awarded to it. The amount of any additional financial assurance provided by a Designated FTR Participant in connection with an unsuccessful bid in an FTR Auction which, as a result of such bid being unsuccessful, is in excess of its FTR Financial Assurance Requirements will be held by the ISO and will be applied against future FTR bids by and awards to that Designated FTR Participant unless that Designated FTR Participant requests in writing to have such excess financial assurance returned to it. Prior to returning any financial assurance to a Designated FTR Participant, the ISO shall use such financial assurance to satisfy any overdue obligations of that Designated FTR Participant. The ISO shall only return to that

Designated FTR Participant the balance of such financial assurance after all such overdue obligations have been satisfied.

## VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy (each a "Designated FCM Participant"), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the "FCM Financial Assurance Requirements"). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.

### A. FCM Delivery Financial Assurance

Each Designated FCM Participant that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter, shall be subject to a "Corporate Liquidity Assessment" as described in this Section VII.A to determine its FCM Delivery Financial Assurance.

#### 1. FCM Delivery Financial Assurance Calculation

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant's FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero.

FCM Delivery Financial Assurance is calculated according to the following formula for a Designated FCM Participant that has a Capacity Supply Obligation up to and including the end of the Capacity Commitment Period associated with the fifteenth Forward Capacity Auction:

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

FCM Delivery Financial Assurance is calculated according to the following applicable formula for a Designated FCM Participant that has a Capacity Supply Obligation commencing at the beginning of the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction and every Capacity Commitment Period thereafter. The applicable FCM Delivery Financial Assurance formula is determined by the results of a Corporate Liquidity Assessment and is limited by the operation of the applicable stop-loss mechanisms as set forth in Market Rule 1 (including those that may apply in the next Capacity Commitment Period).

Corporate Liquidity Assessment Result: Low Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

Corporate Liquidity Assessment Result: Medium Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1]

Corporate Liquidity Assessment Result: High Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1] – Second Largest Monthly Stop-loss x max[(ABR – CWAP), 0.1]

Where:

MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, which have not yet been invoiced in instances where the MCC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MCC is a charge to the Designated FCM Participant. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

IMC (intra-month collateral) equals estimated monthly capacity payments incurred during the current delivery month as limited by the difference (which shall in no event be less than zero) between (A) the minimum of the applicable monthly stop-loss and the remaining annual stop-loss as described in Section III.13.7.3.1 and Section III.13.7.3.2 of Market Rule 1, respectively, and (B) the amount of additional FCM Delivery Financial Assurance when considering the Designated FCM Participant's current month FCM Delivery Financial Assurance obligation as compared to the Designated FCM Participant's next month FCM Delivery Financial Assurance obligation, in each case without giving effect to the IMC and MCC variables when calculating such additional amount. Where the estimated monthly capacity payments for each Designated FCM Participant, shall be updated three (3) days after publication of the most recent FCM Preliminary Capacity Performance Score report (or equivalent report) on the Market Information Server.

DFAMW (delivery financial assurance MW) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.

PE (potential exposure) is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the current Capacity Commitment Period and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7 of Market Rule 1, the Forward

Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. For the purpose of calculating the ABR, all Capacity Balancing Ratios, including Capacity Balancing Ratios for Capacity Scarcity Conditions that occurred in past Capacity Commitment Periods or in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, shall be calculated utilizing the Capacity Balancing Ratio formula that is currently effective, as described in Section III.13.7.2.3 or Section III.15.8.2.3 of Market Rule 1. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60.

CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months

in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall equal 0.65; the temporary average performance for all other resources shall equal 1.00. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

| | |
|---|---|
| June and December | 2.000; |
| July and January | 1.732; |
| August and February | 1.414; |
| All other months | 1.000. |

Peak Monthly Stop-loss equals the largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

Second Largest Monthly Stop-loss equals the second largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

**2. Corporate Liquidity Assessment Methodology**

The ISO will perform a "Corporate Liquidity Assessment" to determine the appropriate liquidity risk assessment category for each Designated FCM Participant (i.e., low risk,

medium risk, or high risk) that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter.

(a) For each Designated FCM Participant, the Corporate Liquidity Assessment shall be performed as follows:
- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest but greater than or equal to the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered medium risk; and
- When the Available Corporate Liquidity is less than the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered high risk.

(b) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from the same Affiliate, or for Designated FCM Participants that are also providing a guaranty (in accordance with this Section VII.A) for an Affiliate:
- The respective Designated FCM Participants will be assessed as a whole and will be collectively assigned one Corporate Liquidity Assessment result (i.e., low risk, medium risk, or high risk);
- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest aggregated Applicable Monthly Stop-losses but is greater than or equal to the sum of two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered medium risk; and

- When the Available Corporate Liquidity is less than the sum of the two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered high risk.

(c) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from multiple Affiliates:

- The guarantors' financial statements will be considered on an aggregate basis for purposes of the Available Corporate Liquidity calculation taking into account other guaranties provided by any such guarantor under this Section VII.A.

Where:

Calculation Period is the current delivery month through the following five consecutive months.

The Applicable Monthly Stop-loss equals the sum of the monthly stop-losses for each resource in a Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1 for the corresponding months within the Calculation Period.

Available Corporate Liquidity is the sum of unrestricted cash and cash equivalents; marketable securities and money market instruments; undrawn committed credit facilities not expiring within three months of the date of the applicable financial statements; and excess financial assurance. Other than with respect to excess financial assurance, such values shall be (a) as reflected on the most recent financial statements provided by the Designated FCM Participant, provided that such financial statements were provided for the most recently completed financial reporting period and compliant with the requirements of this Section VII.A, and (b) calculated in accordance with international accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied. Excess financial assurance shall be calculated as any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant covering its FCM Delivery Financial Assurance obligations plus any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant in excess of its total

Financial Assurance Obligations, each as reflected in the ISO's Financial Assurance Management (FAM) or equivalent system.

For the avoidance of doubt, the components of the Available Corporate Liquidity calculation that are derived from financial statements shall be based on the financial statements of the Designated FCM Participant unless it provides an Affiliate guaranty in compliance with this Section VII.A, in which case the values shall be based on the financial statements of the entity(ies) providing the guaranty. If an acceptable Affiliate guaranty is provided, stop-loss and excess financial assurance values will still be based on the Designated FCM Participant.

Each Designated FCM Participant shall submit to the ISO, on a quarterly basis, its (or its guarantor's, as applicable) audited or unaudited balance sheet or equivalent financial statements, which shall show sufficient detail for the ISO to assess the Designated FCM Participant's (or guarantor's, as applicable) Available Corporate Liquidity. Such financial information shall be accompanied by a certificate from a Senior Officer of the Designated FCM Participant (or guarantor as applicable) that provides the relevant financial information and certifies the accuracy of the attached financial statements. If an attestation was made by an independent accounting firm, then the certificate shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required. The ISO shall post a generally acceptable "clean" form of certificate on its website. Financial statements provided on a quarterly basis shall be submitted within 10 days of such statements becoming available and within 65 days after the end of the applicable fiscal quarter.

Designated FCM Participants that are assessed as medium risk or high risk may elect to provide financial statements on a monthly basis until such a time as they are subsequently assessed as a lower risk category (e.g., from high risk to medium risk, medium risk to low risk, or high risk to low risk); provided that such election shall be for a minimum period of six continuous months during which they are continuously assessed at a lower risk category. Financial statements submitted on a monthly basis are required to be provided to the ISO within 20 days after the end of the prior month and otherwise be provided in accordance with this Section VII.A.

A Designated FCM Participant may choose not to submit financial statements as described in this Section VII.A. If a Designated FCM Participant chooses not to submit financial statements as described in this Section VII.A or if such financial statements are not compliant with the requirements described in this Section VII.A, the ISO shall use a value of $0.00 for Available Corporate Liquidity values derived from financial statements until such time as compliant financial statements are provided.

The ISO shall review the information provided pursuant to this Section VII.A on a rolling basis and will calculate the Available Corporate Liquidity within a reasonable time period which shall not exceed 30 Business Days from the date of receipt.

**3. FCM Affiliate Guaranties**

For the purposes of the Corporate Liquidity Assessment, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from an Affiliate to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant. Upon the ISO's acceptance of an Affiliate guaranty, the guarantor(s) must provide financial statements in accordance with this Section VII.A, and the Corporate Liquidity Assessment will be performed based on the financial information of the guarantor(s). The ISO will post a generally acceptable sample "clean" guaranty on its website, and all guaranties provided pursuant to this Section VII.A shall be in such form with only non-material changes (as determined by the ISO in its sole discretion). The ISO in its sole discretion may update the form guaranty from time to time. The ISO has the right to draw upon the guaranty in the event of a default under the ISO New England Billing Policy up to any amount owed for unpaid Capacity Performance Payments. At any time, the ISO may in its sole discretion provide notice to a Designated FCM Participant that it is choosing to reject or terminate its Affiliate guaranty because such guaranty presents unreasonable risk to the ISO or the New England Markets. In the case of a termination (or planned termination), upon the ISO providing such notice the guaranty shall not be considered for purposes of such Designated FCM Participant's Corporate Liquidity Assessment beginning at 8:30 a.m. on the next Business Day, provided that the ISO may, in its sole discretion, extend this period by up to twenty (20) Business Days. For the avoidance of doubt, notice from the ISO to the Designated FCM Participant that the guaranty its Affiliate provided is being terminated (or will be

terminated), does not constitute a termination notice under such guaranty and the ISO, in its sole discretion, may choose when to send the applicable termination notice under the terms of such guaranty.

In the ISO's sole discretion, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from multiple Affiliates to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant, so long as such guaranty is otherwise in accordance with this Section VII.A and the guarantors have joint and several liability under such guaranty.

**B. Non-Commercial Capacity**

Notwithstanding any provision of this Section VII to the contrary, a Designated FCM Participant offering Non-Commercial Capacity for a Resource that elected existing Resource treatment for the Capacity Commitment Period beginning June 1, 2010 will not be subject to the provisions of this Section VII.B with respect to that Resource (other than financial assurance obligations relating to transfers of Capacity Supply Obligations).

**1. FCM Deposit**

A Designated FCM Participant offering Non-Commercial Capacity into any upcoming Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day after its qualification for such auction under Market Rule 1, an amount equal to $2/kW times the Non-Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant (the "FCM Deposit").

**2. Non-Commercial Capacity in Forward Capacity Auctions**

**a. [Reserved for Future Use]**

**b. Non-Commercial Capacity Participating in Forward Capacity Auctions**

A Designated FCM Participant offering Non-Commercial Capacity into the Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8

a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction an amount calculated according to the following formula:

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) – FCM Deposit

Where:
NCC = the amount of Qualified Capacity that the ISO has qualified for the Designated FCM Participant for the Forward Capacity Auction minus any Commercial Capacity

NCCFCA$ = the Net CONE associated with the Forward Capacity Auction for which the NCC has qualified (adjusted as described in Section III.13.2.4).

Multiplier = one if the auction occurs within 40 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; two if the auction occurs within 28 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; and three if the auction begins within 16 months of the commencement of the Capacity Commitment Period for which the NCC has qualified.

FCM Deposit = $2/kW times the Non Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant

Upon completion of the Forward Capacity Auction, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated according to the following formula:

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) + NCC Trading FA

Where:
NCC = the Capacity Supply Obligation awarded to the Designated FCM Participant in the Forward Capacity Auction minus any Commercial Capacity

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the thirteenth Forward Capacity Auction, NCCFCA$ = the Capacity Clearing Price from the first run of the auction-clearing process of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded. For Capacity Supply Obligations acquired in the fourteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCCFCA$ = the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4).

Multiplier = one beginning at 8 a.m. (Eastern Time) on the first Business Day occurring within 40 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded; two beginning at 8 a.m. (Eastern Time) on the first Business Day occurring within 28 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded; and three beginning at 8 a.m. (Eastern Time) on the first Business Day occurring within 16 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded.

In the case of Non-Commercial Capacity that fails to become commercial by the commencement of the Capacity Commitment Period associated with the Forward Capacity Auction in which it was awarded a Capacity Supply Obligation, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated as follows: beginning at 8 a.m. (Eastern Time) on the first Business Day of the second month of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, the Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall be four. The Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall increase by one every six months thereafter until the Non-Commercial Capacity becomes commercial or the Capacity Supply Obligation is terminated.

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the twelfth Forward Capacity Auction, NCC Trading FA = zero. For Capacity Supply Obligations acquired in the thirteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCC Trading FA shall be zero until the start of the

applicable Capacity Commitment Period, at which time NCC Trading FA shall be calculated as described below, except that in no case shall NCC Trading FA be less than zero:

(a) the total amount of NCC that has been shed (whether before or after the start of the Capacity Commitment Period) in any reconfiguration auctions or Capacity Supply Obligation Bilaterals or that is subject to a failure to cover charge pursuant to Section III.13.3.4(b) (but this total amount shall not be greater than NCC); multiplied by

(b) the difference between: (x) the weighted average price at which the Capacity Supply Obligation was acquired in the Forward Capacity Auction (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); and (y) the weighted average price or failure to cover charge rate at which the Capacity Supply Obligation was shed or assessed, as applicable, except that for monthly Capacity Supply Obligation Bilaterals, one of the following prices will be used:

(i) If the Designated FCM Participant does not certify to the ISO that it has not entered into any contract or other transaction with another party regarding the pricing of such Capacity Supply Obligation Bilateral (other than those to be settled by the ISO) that has the effect of deflating its NCC Trading FA, then the lower of: (1) the applicable monthly reconfiguration auction price, and (2) the Capacity Supply Obligation Bilateral price shall be used;

(ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the lower of: (1) the Capacity Supply Obligation Bilateral price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs) shall be used; or

(iii) If neither subsection (i) nor (ii) applies, then the Capacity Supply Obligation Bilateral price shall be used.

plus

(c) the quantity of any Annual Reconfiguration Transactions associated with NCC for the relevant Capacity Commitment Period in which the Designated

FCM Participant is the Capacity Transferring Resource (but this amount shall not be greater than NCC) multiplied by the difference between: (x) the applicable annual reconfiguration auction clearing price, and (y) the transaction price, which shall equal one of the following:

(i) If the Designated FCM Participant does not certify to the ISO that it has not entered into any contract or other transaction with another party regarding the pricing of such Annual Reconfiguration Transaction (other than those to be settled by the ISO) that has the effect of deflating its NCC Trading FA, the transaction price shall be equal to the lower of: (1) the applicable annual reconfiguration auction clearing price, and (2) the applicable Annual Reconfiguration Transaction price;

(ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the transaction price shall be equal to the lower of: (1) the applicable Annual Reconfiguration Transaction price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); or

(iii) If neither subsection (i) nor (ii) applies, then the applicable Annual Reconfiguration Transaction price shall be used.

**c. Non-Commercial Capacity Deferral**

Where the Commission approves a request to defer a Capacity Supply Obligation filed pursuant to Section III.13.3.7 of Market Rule 1, the Designated FCM Participant must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) 30 days after Commission approval of the request to defer, an amount equal to the amount that would apply to a resource that has not achieved commercial operation one year after the start of a Capacity Commitment Period in which it has a Capacity Supply Obligation, as calculated pursuant to Section VII.B.2.a or Section VII.B.2.b, as applicable.

**3. Return of Non-Commercial Capacity Financial Assurance**

Non-Commercial Capacity cleared in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction that is declared commercial and has had its capacity rating verified by the ISO or otherwise becomes a Resource meeting the definition of Commercial Capacity, or that is declared commercial and had a part of its capacity rating verified by the ISO and the applicable Designated FCM Participant indicates no additional portions of that Resource will become commercial, that portion of the Resource shall no longer be considered Non-Commercial Capacity under the ISO New England Financial Assurance Policy and will instead become subject to the provisions of the ISO New England Financial Assurance Policy relating to Commercial Capacity; provided that in either such case, the Designated FCM Participant will need to include in the calculation of its Financial Assurance Requirement an amount attributable to any remaining Non-Commercial Capacity.

Once Non-Commercial Capacity associated with a Capacity Supply Obligation awarded in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter becomes commercial, the Non-Commercial Capacity Financial Assurance Amount for any remaining Non-Commercial Capacity shall be recalculated according to the process outlined above for Non-Commercial Capacity participating in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter.

**4. Credit Test Percentage Consequences for Provisional Members**

If a Provisional Member is required to provide additional financial assurance under the ISO New England Financial Assurance Policy solely in connection with (A) a supply offer of Non-Commercial Capacity into any Forward Capacity Auction and (B) its obligation to pay Participant Expenses as a Provisional Member, and that Provisional Member is maintaining the amount of additional financial assurance required under the ISO New England Financial Assurance Policy, then the provisions of Section III.B of the ISO New England Financial Assurance Policy relating to the consequences of that Market Participant's Market Credit Test Percentage equaling 80 percent (80%) or 90 percent (90%) shall not apply to that Provisional Member.

**C. [Reserved for Future Use]**

**D. Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance**

If a Designated FCM Participant that has acquired Capacity Supply Obligations associated with Non-Commercial Capacity is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy and does not cure such default within the appropriate cure period, or if a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy during the period between the day that is three Business Days before the FCM Deposit is required and the first day of the Forward Capacity Auction and does not cure such default within the appropriate cure period, then: (i) beginning with the first Business Day following the end of such cure period that Designated FCM Participant will be assessed a default charge of one percent (1%) of its total Non-Commercial Capacity Financial Assurance Amount at that time for each Business Day that elapses until it cures its default; and (ii) if such default is not cured by 5:00 p.m. (Eastern Time) on the sooner of (x) the fifth Business Day following the end of such cure period or (y) the second Business Day prior to the start of the next scheduled Forward Capacity Auction or annual reconfiguration auction or annual Capacity Supply Obligation Bilateral submission (such period being referred to herein as the "Non-Commercial Capacity Cure Period"), then, in addition to the other actions described in this Section VII, (A) all Capacity Supply Obligations associated with Non-Commercial Capacity that were awarded to the defaulting Designated FCM Participant in previous Forward Capacity Auctions and reconfiguration auctions and that the defaulting Designated FCM Participant acquired by entering into Capacity Supply Obligation Bilaterals shall be terminated; (B) the defaulting Designated FCM Participant shall be precluded from acquiring any Capacity Supply Obligation that would be associated with Non-Commercial Capacity for which the defaulting Designated FCM Participant has submitted an FCM Deposit; (C) the ISO will (1) draw down the entire amount of the FCM Deposit and the Non-Commercial Capacity Financial Assurance Amount associated with the terminated Capacity Supply Obligations and (2) issue an Invoice to the Designated FCM Participant if there is a shortfall resulting from that Designated FCM Participant's failure to maintain adequate financial assurance hereunder or if the Designated FCM Participant used a Market Credit Limit to meet its FCM Financial Assurance Requirements; and (D) the default charges described in clause (i) above shall not be assessed to that Designated FCM Participant. All default charges collected under clause (i) above will be deposited in the Late Payment Account in accordance with the ISO New England Billing Policy.

If a Designated FCM Participant's Capacity Supply Obligation is terminated under Market Rule 1, the ISO will draw down the entire Non-Commercial Capacity Financial Assurance Amount provided by such Designated FCM Participant with respect to such terminated Capacity Supply Obligation. If the Designated FCM Participant has not provided enough financial assurance to cover the amount due (or that would have been due but for the Designated FCM Participant's positive Market Credit Limit) with respect to such Non-Commercial Capacity Financial Assurance Amount, then the ISO will issue an Invoice to the Designated FCM Participant for the amount due.

**E. Composite FCM Transactions**

For separate resources that seek to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide that capacity (collectively, a "Composite FCM Transaction"), each Designated FCM Participant participating in that Composite FCM Transaction will be responsible for providing the financial assurance required as follows:

1. the FCM Financial Assurance Requirements for each Designated FCM Participant shall be determined solely with respect to the capacity being provided, or sought to be provided, by that Designated FCM Participant;

2. [reserved];

3. if the Composite FCM Transaction involves one or more Resources seeking to provide or providing Non-Commercial Capacity, the Non-Commercial Capacity Financial Assurance Amount under Section VII.B for each Designated FCM Participant with respect to that Composite FCM Transaction will be calculated based on the commercial status of the Non-Commercial Capacity cleared through the Forward Capacity Auction;

4. any Non-Commercial Capacity Financial Assurance Amount provided under Section VII.B by each Designated FCM Participant with respect to each Resource providing Non-Commercial Capacity in the Composite FCM Transaction will be recalculated according to Section VII.B.3 as the corresponding Resource becomes commercial; and

5. in the event that the Capacity Supply Obligation is terminated, Section VII.D shall apply only to the Non-Commercial Capacity of the Designated FCM Participant participating in the Composite FCM Transaction that has failed to satisfy its obligations, and any Invoice issued thereunder will be issued only to that Designated FCM Participant.

6. the FCM Delivery Financial Assurance calculated under Section VII.A for each Designated FCM Participant contributing resources to a Composite FCM Transaction shall be based on the Capacity Supply Obligation that is provided by that Designated FCM Participant in the current month of the Capacity Commitment Period, provided that the FCM charges incurred in previous months, but not yet paid, shall increase the FCM Financial Assurance Requirements only of the Designated FCM Participant that incurred the charges.

## F. Transfer of Capacity Supply Obligations

### 1. Transfer of Capacity Supply Obligations in Reconfiguration Auctions

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a reconfiguration auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of bidding in that reconfiguration auction, the amounts described in subsections (a) and (b) below.

(a) For the 12 month period beginning with the current month, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For purposes of this subsection (a), months in this period in which that Designated FCM Participant's net FCM revenue results in a credit are disregarded (i.e., the net credits from such months are not used to reduce the amount described in this subsection (a)) and the current month FCM charges are prorated to the proportion of remaining days in the month. The amount described in this subsection (a), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

(b) For the period including each month that is after the period described in subsection (a) above and that is included in a Capacity Commitment Period for which a Forward Capacity Auction has been conducted, the sum of that Designated FCM Participant's net

monthly FCM charges for each month in which the net FCM revenue results in a charge. For this period, the sum of such charges may be offset by net credits from months in which the net FCM revenue results in a credit, but in no case will the amount described in this subsection (b) be less than zero. The amount described in this subsection (b), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

For purposes of these calculations, the net FCM revenue for a month shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations, demand bids and Annual Reconfiguration Transactions in the Forward Capacity Market, exclusive of any accrued Capacity Performance Payments on positions currently or previously held. Upon the completion of each reconfiguration auction, the amount to be included in the calculation of any FCM Financial Assurance Requirements of that Designated FCM Participant shall be adjusted to reflect the cleared quantities at the zonal clearing price for all activity in that reconfiguration auction and accepted Annual Reconfiguration Transactions.

**2. Transfer of Capacity Supply Obligations in Capacity Supply Obligation Bilaterals**

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a Capacity Supply Obligation Bilateral must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Capacity Supply Obligation Bilateral, amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Capacity Supply Obligation Bilaterals, all of those transactions will be rejected. If the Designated FCM Participant's request to transfer a Capacity Supply Obligation in a Capacity Supply Obligation Bilateral is not accepted, it will no longer include amounts related to that Capacity Supply Obligation in the calculation of its FCM Financial Assurance Requirements.

**3. Financial Assurance for Annual Reconfiguration Transactions**

A Designated FCM Participant that submits an Annual Reconfiguration Transaction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Annual Reconfiguration Transaction, amounts calculated as described in Section

VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Annual Reconfiguration Transactions, all of those transactions will be rejected. If a transaction is rejected, the Designated FCM Participant is no longer required to include amounts related to that transaction in the calculation of its FCM Financial Assurance Requirements.

**4. Substitution Auctions**

A Designated FCM Participant that participates in a substitution auction must include the following charges and credits in its FCM Financial Assurance Requirements.

a. For any supply offer with at least one price-quantity pair priced less than zero must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing any price-quantity pairs priced less than zero for each month of the Capacity Commitment Period associated with the Forward Capacity Auction shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

b. A Designated FCM Participant (i) that submits a demand bid into a substitution auction for a resource that is subject to a multi-year rate pursuant to Section III.13.1.3.5.4 or Section III.13.1.1.2.2.4, (ii) for which the maximum charge that would result from clearing the capacity subject to the multi-year rate election would exceed the revenue the Designated FCM Participant will receive for the relevant Capacity Commitment Period under its multi-year rate election for the resource, (iii) must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing the capacity subject to the multi-year rate election shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity

Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

c. If a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction and does not cure such default by the earlier of (i) the end of the appropriate cure period and (ii) 5 p.m. (Eastern Time) on the second Business Day prior to the start of the Forward Capacity Auction, then the defaulting Designated FCM Participant shall be precluded from submitting a supply offer or demand bid that is subject to this Section VII.F.4.

d. Upon the completion of the substitution auction, the amount to be included in the calculation of the FCM Financial Assurance Requirements for a Designated FCM Participant as described in Section VII.F.1 above shall be adjusted to reflect all charges and credits related to the purchase or sale of Capacity Supply Obligations in the substitution auction.

## VIII. [Reserved]

## IX. THIRD-PARTY CREDIT PROTECTION

The ISO shall obtain third-party credit protection, in the form of credit insurance coverage ("Credit Coverage"), on terms acceptable to the ISO in its reasonable discretion at least in an amount covering collectively the Credit Qualifying Rated Market Participants based on the formula below. Notwithstanding the foregoing, if the entity providing such Credit Coverage cannot provide the amount required by this Section IX, the ISO will reduce the required coverage for all Credit Qualifying Rated Market Participants on a pro rata basis. The total amount of the Credit Coverage shall be at least the aggregate of the following formula; provided, however, if the entity providing the Credit Coverage denies coverage (in whole or in part) for any Credit Qualifying Rated Market Participant based on its rights under the insurance policy, the ISO will use reasonable efforts to obtain documentation regarding the denial and will make reasonable efforts to appeal such denial. For each Credit Qualifying Rated Market Participant, the portion of the Credit Coverage shall be the lesser of: (A) the sum of (x) 2.5 times the average Hourly Charges for such Credit Qualifying Rated Market Participant within the previous fifty-two calendar weeks plus (y) 2.5 times the sum of the average Non-Hourly Charges (excluding charges or credits related to FTR transactions) and the average Transmission Charges for such Credit Qualifying

Rated Market Participant within the previous twelve calendar months; or (B) $50 million. For any Credit Qualifying Rated Market Participant, the applicable amount of the Credit Coverage shall be adjusted monthly if the above formula produces a change that is either (A) 10% or greater, or (B) greater than $100,000. The Credit Coverage shall be provided by an insurance company rated "A-" or better by A.M. Best & Co. or "A" or better by S&P. The cost of the Credit Coverage obtained for each calendar year shall be allocated to all Credit Qualifying Rated Market Participants pro rata based, for each Credit Qualifying Rated Market Participant, on the average amount of the Invoices issued to that Credit Qualifying Rated Market Participant under the ISO New England Billing Policy in the preceding calendar year. Each Credit Qualifying Rated Market Participant shall provide the ISO with such information as may be reasonably necessary for the ISO to obtain the Credit Coverage at the lowest possible cost.

## X. ACCEPTABLE FORMS OF FINANCIAL ASSURANCE

Provided that the requirements set forth herein are satisfied, acceptable forms of financial assurance include shares of registered or private mutual funds held in a shareholder account or a letter of credit, each in accordance with the provisions of this Section X. All costs associated with obtaining financial security and meeting the provisions of the ISO New England Financial Assurance Policy are the responsibility of the Market Participant or Non-Market Participant Transmission Customer providing that security (each a "Posting Entity").

### A. Shares of Registered or Private Mutual Funds in a Shareholder Account

Shares of registered or private mutual funds in a shareholder account are an acceptable form of financial assurance provided that the Posting Entity providing such collateral (i) completes all required documentation to open an account with the financial institution selected by the ISO, after consultation with the NEPOOL Budget and Finance Subcommittee, (ii) completes and executes a security agreement ("Security Agreement") in the form of Attachment 1 to the ISO New England Financial Assurance Policy (as may be modified pursuant to Section X.B.1) and is in compliance with the Security Agreement, and (iii) completes and executes a Control Agreement in the form posted on the ISO website (as may be modified pursuant to Section X.B.1) and is in compliance with the Control Agreement. Any material variation from the form of Security Agreement included in Attachment 1 to the ISO New England Financial Assurance Policy (other than as modified pursuant to Section X.B.1) or the form of Control Agreement (other than as modified pursuant to Section X.B.1) posted on the ISO website must be approved by the ISO after consultation with the NEPOOL Budget and Finance

Subcommittee and, in the case of the Security Agreement, filed with the Commission. To the extent any amount of shares contained in the shareholder account is no longer required hereunder, the ISO shall return such collateral to the Posting Entity providing it within four (4) Business Days of a request to do so.

If the amount of collateral maintained in the shareholder account is below the required level (including by reason of losses on investments), the Posting Entity shall immediately replenish or increase the amount to the required level. The collateral will be held in an account maintained in the name of the Posting Entity and invested in the investment selected by that Posting Entity from a menu of investment options listed at the time on the ISO's website, which menu will be approved by the NEPOOL Budget and Finance Subcommittee, with discounts applied to the investments in certain of such options if and as determined by the NEPOOL Budget and Finance Subcommittee. If a Posting Entity does not select an investment for its collateral, that collateral will be invested in the "default" investment option selected by the ISO and approved by the NEPOOL Budget and Finance Subcommittee from time to time. Any dividends and distribution on such investment will accrue to the benefit of the Posting Entity. The ISO may sell or otherwise liquidate such investments at its discretion to meet the Posting Entity's obligations to the ISO. In no event will the ISO or NEPOOL or any NEPOOL Participant have any liability with respect to the investment of collateral under this Section X.A.

Notwithstanding the foregoing, an investment in shares of a registered fund in a shareholder account shall not be an acceptable form of financial assurance for a Posting Entity that is not a U.S. Person, as defined in Regulation S under the Securities Act of 1933, as amended, unless the financial institution selected by the ISO allows such Posting Entity to invest in the investment options listed at the time on the ISO's website or the Posting Entity is invested in the investment options listed on the ISO's website as of March 19, 2015.

**B. Letter of Credit**

An irrevocable standby letter of credit provides an acceptable form of financial assurance to the ISO. For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the end of the Business Day that is 30 days prior to the

termination of such letter of credit. If the letter of credit amount is below the required level, the Posting Entity shall immediately replenish or increase the letter of credit amount or obtain a substitute letter of credit. The account party on a letter of credit must be either the Posting Entity whose obligations are secured by that letter of credit or an Affiliate of that Posting Entity.

**1. Risk Mitigation Draws**

The ISO may draw against a letter of credit for two reasons in addition to a failure to pay under the ISO New England Billing Policy: i) an expiring letter of credit has not been renewed, or ii) the issuing bank is downgraded below the minimum ratings requirement, each in accordance with the terms of the letter of credit (the "Risk Mitigation Draws"). The ISO may exercise its rights under the Risk Mitigation Draws up to the amount that a Posting Entity's financial assurance requirements are not covered by acceptable forms of financial assurance. The ISO will hold such funds as a security deposit for the satisfaction of all obligations owed to the ISO by the Posting Entity (the "Risk Mitigation Drawn Funds"). The Risk Mitigation Drawn Funds shall be considered an appropriate form of financial assurance as described in this Section X. The ISO will hold all right, title, and interest in the Risk Mitigation Drawn Funds and the Posting Entity shall have a contingent right to such funds less any amounts applied to any debts owed to the ISO (pursuant to the Tariff, including the ISO New England Billing Policy): (i) upon the termination of its Market Participant Financial Assurance Requirement in accordance with Section III of the Financial Assurance Policy, (ii) upon the Posting Entity's provision of an alternative form of acceptable financial assurance in accordance with this Section X, or (iii) to the extent that any portion of the Risk Mitigation Drawn Funds are no longer required hereunder, upon the Posting Entity providing a written request to the ISO to return such portion of the funds (which request shall be honored within four (4) Business Days).

Upon request of the ISO, but no later than five (5) Business Days after the Risk Mitigation Draw, the Posting Entity shall execute a Security Agreement in the form of Attachment 1 to the ISO New England Financial Assurance Policy, provided that such form shall be modified to include within the definition of Collateral, funds received from a Risk Mitigation Draw, or an amendment to its existing Security Agreement in a form acceptable to the ISO in its sole discretion. Within thirty (30) days of the Risk Mitigation

Draw the Posting Entity shall satisfy its obligations pursuant to the paragraph immediately below to direct the deposit of the Risk Mitigation Drawn Funds into the Posting Entity's shareholder account as described in Section X.A. Notwithstanding the prior sentence, if the Posting Entity provides written documentation to the ISO (which documentation must be to the ISO's reasonable satisfaction) of its inability to open a shareholder account as described in Section X.A, and the Posting Entity has executed a Security Agreement or an amendment to its existing Security Agreement as required above, the ISO shall continue to hold the Risk Mitigation Drawn Funds (and such amount shall continue to be considered financial assurance), subject to the Posting Entity's contingent right to such funds as described above, in a form determined by the ISO in its sole discretion, and any interest or income accrued on such funds, if applicable, shall be considered part of the Posting Entity's financial assurance.

Upon a Risk Mitigation Draw and unless the Posting Entity has either posted other appropriate financial assurance in the forms permitted by this Section X or provided written documentation of its inability to do so in accordance with the preceding paragraph, the Posting Entity shall within thirty (30) days of the Risk Mitigation Draw complete any steps required by the ISO to (a) open a shareholder account as described in Section X.A, (b) execute any necessary documentation, including any amendments to the Security Agreement and Control Agreement deemed necessary by the ISO in a form acceptable to the ISO in its sole discretion, for the ISO to deposit the Risk Mitigation Drawn Funds into the Posting Entity's shareholder account, and (c) direct the ISO to deposit the Risk Mitigation Default Drawn Funds into that Posting Entity's shareholder account as described in Section X.A. Upon the Posting Entity's completion of the foregoing steps in (a) through (c) to the ISO's satisfaction, ISO shall deposit the Risk Mitigation Default Drawn Funds into that Posting Entity's shareholder account and the balance of the funds then on deposit in such account shall continue to be the collateral of the ISO.

The ISO may apply any funds received from a letter of credit, including the Risk Mitigation Drawn Funds held as a security deposit, to amounts owed by the Posting Entity in accordance with the ISO New England Billing Policy. If a Posting Entity fails to comply with the provisions of this Section X.B.1, then the Posting Entity will be

suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

**2. Requirements for Banks**

Each bank issuing a letter of credit that serves as financial assurance must meet the requirements of this Section X.B.2. Each such bank must be on the ISO's "List of Eligible Letter of Credit Issuers" which shall be established pursuant to this Section X.B.2. The ISO will post the current List of Eligible Letter of Credit Issuers on its website, and update that List and posting no less frequently than quarterly; provided that if a change is made to the List of Eligible Letter of Credit Issuers, the ISO shall update the List and provide notice to the NEPOOL Budget & Finance Subcommittee. To be included on the List of Eligible Letter of Credit Issuers, (i) the bank must be organized under the laws of the United States or any state thereof, or be the United States branch of a foreign bank; (ii) have a minimum long-term debt rating (or, if the bank does not have a minimum long-term debt rating, than a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's, or "A-" by Fitch; and (iii) be approved by the ISO in its sole discretion. In the event that a bank is rated by multiple Rating Agencies, if any applicable rating from the Rating Agencies falls below the levels listed, then a bank will not be considered to have satisfied the requirement under this paragraph. In addition, no Posting Entity may provide a letter of credit that has been issued by a bank that is an Affiliate of that Market Participant.

If a bank that is included on the List of Eligible Letter of Credit Issuers fails to satisfy the criteria set forth above or if the ISO determines in its sole discretion that despite satisfying the criteria set forth above, accepting a letter of credit from a bank on the List of Eligible Letter of Credit Issuers presents an unreasonable risk that a bank may fail to honor the terms of such letter of credit, the applicable Posting Entity will have five (5) Business Days from the date on which the ISO provides notice of such failure or removal to replace the letter of credit with a letter of credit from a bank satisfying the criteria or provide other financial assurance satisfying the requirements of the ISO New England Financial Assurance Policy. The ISO may extend that cure period to twenty (20) Business Days in its sole discretion. The ISO must promptly advise the NEPOOL Budget and Finance Subcommittee of any extension of a cure period beyond five (5) Business Days under this provision. For purposes of the ISO New England Financial

Assurance Policy, the letter of credit shall be valued at $0 at the expiration of the five (5) or twenty (20) Business Day cure period, as applicable.

No letter of credit bank may issue letters of credit under the ISO New England Financial Assurance Policy in an amount exceeding either: (i) $100 million in the aggregate for any single Posting Entity; or (ii) $150 million in aggregate for a group of Posting Entities that are Affiliates. If a bank is removed from the List of Eligible Letter of Credit Issuers based on the ISO's determination that there is an unreasonable risk that a bank may fail to honor the terms of such letter of credit, the ISO in its sole discretion may reinstate eligibility, provided that the bank otherwise meets the conditions of this Section X.B.2.

The following provisions shall apply when a bank fails to honor the terms of one or more letters of credit issued by the bank in favor of the ISO: (i) if the bank fails to honor the terms of one letter of credit in a rolling seven hundred and thirty day period, then the ISO will issue a notice of such failure to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contracts for all Market Participants; (ii) if the bank fails to honor either the terms of one letter of credit twice or the terms of two letters of credit in a rolling seven hundred and thirty day period, then (A) the ISO shall issue a notice described in subsection (i) above, (B) the bank will no longer be eligible to issue letters of credit in favor of the ISO, (C) any letters of credit issued by such bank in favor of the ISO will not be renewed, and (D) any letters of credit issued by such bank in favor of the ISO must be replaced with another acceptable form of financial assurance within five (5) Business Days from the date on which the ISO provides notice of such failure (the ISO may extend that cure period to twenty (20) Business Days in its sole discretion). For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the expiration of the five (5) or twenty (20) Business Day cure period, as applicable. Notwithstanding the foregoing, the ISO in its sole discretion may reinstate eligibility after not less than two years from the loss of eligibility, provided that the bank otherwise meets the conditions of this Section X.B.2.

**3. Form of Letter of Credit**

Attachment 2 provides a generally acceptable sample "clean" letter of credit, and all letters of credit provided by Posting Entities shall be in this form (with only minor, non-material changes), unless a variation therefrom is approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and filed with the Commission. Notwithstanding the foregoing, Posting Entities that have provided a letter of credit in a form that was previously acceptable (e.g., under a prior version of Attachment 2) shall not be required to resubmit such letter of credit until the earlier of (a) the amendment or expiration of such letter of credit, in which case Posting Entity shall be required to provide a letter of credit in the form of Attachment 2, or (b) September 1, 2026. Any letter of credit provided for a new Posting Entity, for the purpose of covering the Initial Market Participant Financial Assurance Requirement, must have a minimum term of 120 days. All costs incurred by the ISO in collecting on a letter of credit provided under the ISO New England Financial Assurance Policy shall be paid, or reimbursed to the ISO, by the Posting Entity providing that letter of credit.

**C. Special Provisions for Provisional Members**

Notwithstanding any other provision of the ISO New England Financial Assurance Policy to the contrary, due to the temporary nature of a Market Participant's status as a Provisional Member and the relatively small amounts due from Provisional Members, any Provisional Member required to provide additional financial assurance under the ISO New England Financial Assurance Policy may only satisfy the portion of that requirement attributable to Participant Expenses under the RNA by providing collateral maintained in a shareholder account in accordance with Section X.A. Provisional Members will not have any other Non-Hourly Requirements under the ISO New England Financial Assurance Policy. If a Provisional Member uses a standing instruction to pay its Invoices pursuant to the ISO New England Billing Policy, in order to avoid a default and/or a Late Payment Charge, the total amount of collateral maintained in a shareholder account by that Provisional Member should be equal to the sum of (x) the Provisional Member's Financial Assurance Requirement under the ISO New England Financial Assurance Policy that is attributable to Participant Expenses under the RNA and (y) the amount due from that Provisional Member on its next Invoice under that ISO New England Billing Policy (not including the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Provisional Member). Provisional Members are also required to satisfy all other

provisions of the ISO New England Financial Assurance Policy, and any additional financial assurance required to be provided by a Provisional Member that is not attributable to Participant Expenses may be satisfied by providing an acceptable form of financial assurance in accordance with this Section X. Without limiting or reducing in any way the requirements of the ISO New England Financial Assurance Policy that apply to a Provisional Member, the amount of collateral maintained in a shareholder account initially provided by a Provisional Member that is attributable to Participant Expenses (including any amounts provided in connection with the standing instruction under the ISO New England Billing Policy described above) shall be at least $2,500, and each Provisional Member will replenish that collateral maintained in a shareholder account to at least that $2,500 level on December 31 of each year.

## XI. MISCELLANEOUS PROVISIONS

### A. Obligation to Report Material Adverse Changes

Each Market Participant and each Non-Market Participant Transmission Customer is responsible for informing the ISO in writing within five (5) Business Days of any Material Adverse Change in its financial status. A "Material Adverse Change" in financial status includes, but is not limited to, the following: 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 Principals imposed 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; the filing of a material lawsuit that could materially adversely impact current or future financial results; or a significant change in the Market Participant's or Non-Market Participant Transmission Customer's market capitalization. A Market Participant's or Non-Market Participant Transmission Customer's failure to timely disclose a Material Adverse Change in its financial status may result in termination proceedings by the ISO. If the ISO determines that there is a Material Adverse Change in the financial condition

of a Market Participant- or Non-Market Participant Transmission Customer, then the ISO shall provide to that Market Participant or Non-Market Participant Transmission Customer a signed written notice two Business Days before taking any of the actions described below. The notice shall explain the reasons for the ISO's determination of the Material Adverse Change. After providing notice, the ISO may take one or more of the following actions: (i) require that, within two Business Days of receipt of the notice of Material Adverse Change, the Market Participant or Non-Market Participant Transmission Customer provide one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy and/or an additional amount of financial assurance in one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy; (ii) require that the Market Participant or Non-Market Participant Transmission Customer cease one or more transactions in the New England Markets; or (iii) require that the Market Participant or Non-Market Participant Transmission Customer take other measures to restore the ISO's confidence in its ability to safely transact in the New England Markets. Any additional amount of financial assurance required as a result of a Material Adverse Change shall be sufficient, as reasonably determined by the ISO, to cover the Market Participant's or Non-Market Participant Transmission Customer's potential settled and unsettled liability or obligation, provided, however, that if the additional amount of financial assurance required as a result of a Material Adverse Change is equal to or greater than $25 million, then the Chief Financial Officer shall first consult, to the extent practicable, with the ISO's Chief Executive Officer, Chief Operating Officer, and General Counsel. If the Market Participant or Non-Market Participant Transmission Customer fails to comply with any of the requirements imposed as a result of a Material Adverse Change, then the ISO may initiate termination proceedings against the Market Participant or Non-Market Participant Transmission Customer.

**B. Weekly Payments**

A Market Participant or Non-Market Participant Transmission Customer may request that, in lieu of providing the entire amount of one of the financial assurances set forth above to satisfy its Financial Assurance Requirement, a weekly billing schedule be implemented for its Non-Hourly Charges and its Transmission Charges. The ISO may, in its discretion, agree to such a request; provided, however, that any weekly billing arrangement for Non-Hourly Charges and Transmission Charges will terminate no more

than six (6) months after the date on which such arrangement begins unless the Market Participant or Non-Market Participant Transmission Customer requests an extension of such arrangement and demonstrates to the ISO's satisfaction in its sole discretion that the termination of such arrangement and compliance with the other provisions of the ISO New England Financial Assurance Policy (including providing the full amount of its Financial Assurance Requirement) will impose a substantial hardship on the Market Participant or Non-Market Participant Transmission Customer. Such demonstration of a substantial hardship shall be made every six (6) months after the initial demonstration, and a Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement for Non-Hourly Charges and Transmission Charges will be terminated if it fails to demonstrate to the ISO's satisfaction in its sole discretion at any such six (6) month interval that compliance with the other provisions of the ISO New England Financial Assurance Policy will impose a substantial hardship on it. If the ISO agrees to implement a weekly billing schedule for Non-Hourly Charges and Transmission Charges for a Market Participant or Non-Market Participant Transmission Customer, the Market Participant or Non-Market Participant Transmission Customer shall be billed weekly for such Non-Hourly Charges and Transmission Charges in accordance with the ISO New England Billing Policy. The Market Participant or Non-Market Participant Transmission Customer shall pay with respect to each weekly Invoice for Non-Hourly Charges and Transmission Charges an administrative fee, determined by the ISO, to reimburse the ISO for the costs it incurs as a result of that Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement.

If a weekly billing schedule is implemented for a Market Participant's or Non-Market Participant Transmission Customer's Non-Hourly Charges and Transmission Charges under this Section XI.B, the Market Participant or Non-Market Participant Transmission Customer may be required to provide the full amount of its Financial Assurance Requirement at any time if the Market Participant or Non-Market Participant Transmission Customer fails to pay when due any weekly Invoice. In addition, upon the termination of a Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement for Non-Hourly Charges and Transmission Charges, the Market Participant or Non-Market Participant Transmission Customer shall either satisfy the applicable rating requirements set forth herein, satisfy the Credit

Threshold, or provide the full amount of one of the other forms of financial assurance set forth herein.

**C. Use of Transaction Setoffs**

In the event that a Market Participant or Non-Market Participant Transmission Customer has failed to satisfy its Financial Assurance Requirement hereunder, the ISO may retain payments due to such Market Participant or Non-Market Participant Transmission Customer, up to the amount of such Market Participant's or Non-Market Participant Transmission Customer's unsatisfied Financial Assurance Requirement, as a cash deposit securing such Market Participant's or Non-Market Participant Transmission Customer's obligations to the ISO, NEPOOL, the Market Participants, the PTOs and the Non-Market Participant Transmission Customers, provided, however, that a Market Participant or Non-Market Participant Transmission Customer will not be deemed to have satisfied its Financial Assurance Requirement under the ISO New England Financial Assurance Policy because the ISO is retaining amounts due to it hereunder unless such Market Participant or Non-Market Participant Transmission Customer has satisfied all of the requirements of Section X with respect to such amounts.

**D. Reimbursement of Costs**

Each Market Participant or Non-Market Participant Transmission Customer that fails to perform any of its obligations under the Tariff, including without limitation those arising under the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, shall reimburse the ISO, NEPOOL and each Market Participant, PTO and Non-Market Participant Transmission Customer for all of the fees, costs and expenses that they incur as a result of such failure.

**E. Notification of Default**

In the event that a Market Participant or Non-Market Participant Transmission Customer fails to comply with the ISO New England Financial Assurance Policy (a "Financial Assurance Default"), such failure continues for at least two days and notice of that failure has not previously been given, the ISO may (but shall not be required to) notify such Market Participant or Non-Market Participant Transmission Customer in writing, electronically and by first class mail sent in each case to such Market Participant's or Non-Market Participant Transmission Customer's billing and credit contacts or such

Market Participant's member or alternate member on the Participants Committee (it being understood that the ISO will use reasonable efforts to contact all three where applicable), of such Financial Assurance Default. Either simultaneously with the giving of the notice described in the preceding sentence or within two days thereafter (unless the Financial Assurance Default is cured during such period), the ISO shall notify each other member and alternate on the Participants Committee and each Market Participant's and Non-Market Participant Transmission Customer's billing and credit contacts of the identity of the Market Participant or Non-Market Participant Transmission Customer receiving such notice, whether such notice relates to a Financial Assurance Default, and the actions the ISO plans to take and/or has taken in response to such Financial Assurance Default. In addition to the notices provided for herein, the ISO will provide any additional information required under the ISO New England Information Policy.

**F. Remedies Not Exclusive**

No remedy for a Financial Assurance Default is or shall be deemed to be exclusive of any other available remedy or remedies. Each such remedy shall be distinct, separate and cumulative, shall not be deemed inconsistent with or in exclusion of any other available remedy, and shall be in addition to and separate and distinct from every other remedy. A Financial Assurance Default may result in suspension of the Market Participant or Non-Market Participant Transmission Customer or the commencement of termination proceedings by the ISO.

**G. Inquiries and Contests**

A Market Participant or Non-Market Participant Transmission Customer may request a written explanation of the ISO's determination of its Market Credit Limit, Transmission Credit Limit, Financial Assurance Requirement or Transmission Obligations, including any change thereto, by submitting that request in writing to the ISO's Credit Department, either by email at CreditDepartment@iso-ne.com or by facsimile at (413) 540-4569. That request must include the Market Participant's customer identification number, the name of the Market Participant or Non-Market Participant Transmission Customer and the specific information for which the Market Participant or Non-Market Participant Transmission Customer would like an explanation and must be submitted by the designated credit contact for that Market Participant or Non-Market Participant Transmission Customer as on file with the ISO. In addition, since Financial Assurance

Requirements are updated at least daily, any request for an explanation relating to the calculation of, or a change in, a Financial Assurance Requirement must be submitted on the same day as that calculation or change. The ISO's response to any request under this Section XI.G shall include an explanation of how the applicable calculation or determination was performed using the formulas and criteria in the ISO New England Financial Assurance Policy. A Market Participant or Non-Market Participant Transmission Customer may contest any calculation or determination by the ISO under the ISO New England Financial Assurance Policy using the dispute resolution provisions of Section I.6 of the Tariff.

**H. Forward Contract/Swap Agreement**

All FTR transactions constitute "forward contracts" and/or "swap agreements" within the meaning of the United States Bankruptcy Code (the "Bankruptcy Code"), and the ISO shall be deemed to be a "forward contract merchant" and/or "swap participant" within the meaning of the Bankruptcy Code for purposes of those FTR transactions. Pursuant to the ISO New England Financial Assurance Policy, the ISO Tariff and the Market Participant Service Agreement with each Market Participant, the ISO already has, and shall continue to have, the following rights (among other rights) in respect of a Market Participant default under those documents (including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy): A) the right to terminate and/or liquidate any FTR transaction held by that Market Participant; B) the right to immediately proceed against any additional financial assurance provided by that Market Participant; C) the right to set off any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement or similar agreement against any amounts due and owing by that Market Participant pursuant to any forward contract, swap agreement or similar agreement, such arrangement to constitute a "master netting agreement" within the meaning of the Bankruptcy Code; and D) the right to suspend that Market Participant from entering into future transactions in the FTR system. For the avoidance of doubt, upon the commencement of a voluntary or involuntary proceeding for a Market Participant under the Bankruptcy Code, and without limiting any other rights of the ISO or obligations of any Market Participant under the Tariff (including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy) or any Market Participant Service Agreement, the ISO may exercise any of its rights against such Market Participant, including, without limitation 1) the right to

terminate and/or liquidate any FTR transaction held by that Market Participant, 2) the right to immediately proceed against any additional financial assurance provided by that Market Participant, 3) the right to set off any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement and/or master netting agreement against any amounts due and owing by that Market Participant with respect to an FTR transaction including as a result of the actions taken by the ISO pursuant to 1) above, and 4) the right to suspend that Market Participant from entering into future transactions in the FTR system.

**ATTACHMENT 1**

**SECURITY AGREEMENT**

THIS SECURITY AGREEMENT (the "Security Agreement") is effective as of this [__] day of [_____], 20[_], by and between [INSERT NAME], a [_____], having its principal office and place of business at [_____] (the "Debtor"), and ISO New England Inc., a Delaware nonprofit corporation (the "Secured Party" and collectively with the Debtor, the "Parties").

WITNESSETH:

In consideration of the mutual promises and covenants herein contained, the Parties agree as follows:

1. Definitions.

a. In this Security Agreement:

i. "Code" shall mean the Uniform Commercial Code, as enacted in the State of Connecticut and as amended from time to time.

ii. "Collateral" shall mean (a) all cash provided, submitted, wired or otherwise transferred or deposited by the Debtor to or with the Secured Party or a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf, to hold or invest such cash deposit, from time to time in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (b) all securities or other investment property (as defined in the Code) of the Debtor, whether or not purchased with such cash deposit, submitted, wired or otherwise transferred, deposited or maintained by the Debtor to or with the Secured Party or its designee, in each case in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (c) all other property of Debtor submitted, pledged, assigned or otherwise transferred by the Debtor to the Secured Party or its designee, in each case, in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; and (d) the products and proceeds of each of the foregoing.

iii. "ISO Financial Assurance Policy" shall mean the Financial Assurance Policy in the Tariff, as amended, supplemented or restated from time to time, including but not limited to the Financial Assurance Policy in Exhibit 1A to Section I of the Tariff.

iv. "Tariff" shall mean the ISO New England Inc. Transmission, Markets and Services Tariff, as filed with the Federal Energy Regulatory Commission, as amended, supplemented and/or restated from time to time.

v. "Obligations" shall mean any and all amounts due from Debtor from time to time under the Tariff.

vi. "Market Participants" shall have the meaning set forth in the Tariff.

b. Any capitalized term not defined herein that is defined in the Code shall have the meaning as defined in the Code.

2. Security Interest. To secure the payment of all Obligations of the Debtor, Debtor hereby grants and conveys to the Secured Party a security interest in the Collateral. The Debtor hereby irrevocably authorizes the Secured Party at any time and from time to time to file in any applicable filing office any initial financing statements and amendments thereto that provide any information required by part 5 of Article 9 of the Code for the sufficiency or filing office acceptance of any financing statement or amendment.

3. Debtor's Covenants. The Debtor warrants, covenants and agrees with the Secured Party as follows:

a. The Debtor shall perform all of the Debtor's obligations under this Security Agreement according to its terms.

b. The Debtor shall defend the title to the Collateral against any and all persons and against all claims.

c. The Debtor shall at any time and from time to time take such steps as the Secured Party may reasonably request to ensure the continued perfection and priority of the Secured Party's security interest in the Collateral and the preservation of its rights therein.

d. The Debtor acknowledges and agrees that this Security Agreement grants, and is intended to grant, a security interest in the Collateral. If the Debtor is a corporation, limited liability company, limited partnership or other Registered Organization (as that term is defined in Article 9 of the Uniform Commercial Code as in effect in Connecticut) the Debtor shall, at its expense, furnish to Secured Party a certified copy of Debtor's organization documents verifying its correct legal name or, at Secured Party's election, shall permit the Secured Party to obtain such certified copy at Debtor's expense. From

time to time at Secured Party's election, the Secured Party may obtain a certified copy of Debtor's organization documents and a search of such Uniform Commercial Code filing offices, as it shall deem appropriate, at Debtor's expense, to verify Debtor's compliance with the terms of this Security Agreement.

e. The Debtor authorizes the Secured Party, if the Debtor fails to do so, to do all things required of the Debtor herein and charge all expenses incurred by the Secured Party to the Debtor together with interest thereon, which expenses and interest will be added to the Obligations.

4. Debtor's Representations and Warranties. The Debtor represents and warrants to the Secured Party as follows:

a. The exact legal name of the Debtor is as first stated above.

b. Except for the security interest of the Secured Party, Debtor is the owner of the Collateral free and clear of any encumbrance of any nature.

5. Non-Waiver. Waiver of or acquiescence in any default by the Debtor or failure of the Secured Party to insist upon strict performance by the Debtor of any warranties, covenants, or agreements in this Security Agreement shall not constitute a waiver of any subsequent or other default or failure. No failure to exercise or delay in exercising any right, power or remedy of the Secured Party under this Security Agreement shall operate as a waiver thereof, nor shall any partial exercise of any right, power or remedy preclude any other or further exercise thereof or the exercise of any other right, power or remedy. The failure of the Secured Party to insist upon the strict observance or performance of any provision of this Security Agreement shall not be construed as a waiver or relinquishment of such provision. The rights and remedies provided herein are cumulative and not exclusive of any other rights or remedies provided at law or in equity.

6. Events of Default. Any one of the following shall constitute an "Event of Default" hereunder by the Debtor:

a. Failure by the Debtor to comply with or perform any provision of this Security Agreement or to pay any Obligation; or

b. Any representation or warranty made or given by the Debtor in connection with this Security Agreement proves to be false or misleading in any material respect; or

c. Any part of the Collateral is attached, seized, subjected to a writ or distress warrant, or is levied upon, or comes within the possession of any receiver, trustee, custodian or assignee for the benefit of creditors.

7. Remedy upon the Occurrence of an Event of Default. Upon the occurrence of any Event of Default the Secured Party shall, immediately and without notice, be entitled to use, sell, or otherwise liquidate the Collateral to pay all Obligations owed by the Debtor.

8. Attorneys' Fees, etc. Upon the occurrence of any Event of Default, the Secured Party's reasonable attorneys' fees and the legal and other expenses for pursuing, receiving, taking, keeping, selling, and liquidating the Collateral and enforcing the Security Agreement shall be chargeable to the Debtor.

9. Other Rights.

a. In addition to all rights and remedies herein and otherwise available at law or in equity, upon the occurrence of an Event of Default, the Secured Party shall have such other rights and remedies as are set forth in the Tariff and ISO Financial Assurance Policy.

b. Notwithstanding the provisions of the ISO New England Information Policy, as amended, supplemented or restated from time to time (the "ISO New England Information Policy"), Debtor hereby (i) authorizes the Secured Party to disclose any information concerning Debtor to any court, agency or entity which is necessary or desirable, in the sole discretion of the Secured Party, to establish, maintain, perfect or secure the Secured Party's rights and interest in the Collateral (the "Debtor Information"); and (ii) waives any rights it may have under the ISO New England Information Policy to prevent, impair or limit the Secured Party from disclosing such information concerning the Debtor.

10. PRE-JUDGMENT REMEDY. DEBTOR ACKNOWLEDGES THAT THIS SECURITY AGREEMENT AND THE UNDERLYING TRANSACTIONS GIVING RISE HERETO CONSTITUTE COMMERCIAL BUSINESS TRANSACTED WITHIN THE STATE OF CONNECTICUT. IN THE EVENT OF ANY LEGAL ACTION BETWEEN DEBTOR AND

THE SECURED PARTY HEREUNDER, DEBTOR HEREBY EXPRESSLY WAIVES ANY RIGHTS WITH REGARD TO NOTICE, PRIOR HEARING AND ANY OTHER RIGHTS IT MAY HAVE UNDER THE CONNECTICUT GENERAL STATUTES, CHAPTER 903a, AS NOW CONSTITUTED OR HEREAFTER AMENDED, OR OTHER STATUTE OR STATUTES, STATE OR FEDERAL, AFFECTING PREJUDGMENT REMEDIES, AND THE SECURED PARTY MAY INVOKE ANY PREJUDGMENT REMEDY AVAILABLE TO IT, INCLUDING, BUT NOT LIMITED TO, GARNISHMENT, ATTACHMENT, FOREIGN ATTACHMENT AND REPLEVIN, WITH RESPECT TO ANY TANGIBLE OR INTANGIBLE PROPERTY (WHETHER REAL OR PERSONAL) OF DEBTOR TO ENFORCE THE PROVISIONS OF THIS SECURITY AGREEMENT, WITHOUT GIVING DEBTOR ANY NOTICE OR OPPORTUNITY FOR A HEARING.

11. WAIVER OF JURY TRIAL. THE DEBTOR AND THE SECURED PARTY HEREBY EACH KNOWINGLY, VOLUNTARILY AND IRREVOCABLY WAIVES THE RIGHT TO TRIAL BY JURY IN ANY ACTION, DEFENSE, COUNTERCLAIM, CROSSCLAIM AND/OR ANY FORM OF PROCEEDING BROUGHT IN CONNECTION WITH THIS SECURITY AGREEMENT OR RELATING TO ANY OBLIGATIONS SECURED HEREBY.

12. Additional Waivers. Demand, presentment, protest and notice of nonpayment are hereby waived by Debtor. Debtor also waives the benefit of all valuation, appraisement and exemption laws.

13. Binding Effect. The terms, warranties and agreements herein contained shall bind and inure to the benefit of the respective Parties hereto, and their respective legal representatives, successors and assigns.

14. Assignment. The Secured Party may, upon notice to the Debtor, assign without limitation its security interest in the Collateral.

15. Amendment. This Security Agreement may not be altered or amended except by an agreement in writing signed by the Parties.

16. Term.

a. This Security Agreement shall continue in full force and effect until all Obligations owed by the Debtor have been paid in full.

b. No termination of this Security Agreement shall in any way affect or impair the rights and liabilities of the Parties hereto relating to any transaction or events prior to such termination date, or to the Collateral in which the Secured Party has a security interest, and all agreements, warranties and representations of the Debtor shall survive such termination.

17. Choice of Law. The laws of the State of Connecticut shall govern the rights and duties of the Parties herein contained without giving effect to any conflict-of-law principles.

IN WITNESS WHEREOF, the Parties have signed and sealed this Security Agreement as of the day and year first above written.

[INSERT NAME]

By: _____

Name:

Title:

ISO NEW ENGLAND INC.

By:_____

Name:

Title:

**ATTACHMENT 2**

**SAMPLE STANDBY LETTER OF CREDIT**

[DATE PROVIDED]

IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO.

[EXPIRATION DATE]

WE DO HEREBY ISSUE THIS IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT BY ORDER OF AND FOR THE ACCOUNT OF [POSTING ENTITY OR AFFILIATE OF POSTING ENTITY ON BEHALF OF POSTING ENTITY] ("ACCOUNT PARTY") IN FAVOR OF ISO NEW ENGLAND INC. ("ISO" OR "BENEFICIARY") ("STANDBY LETTER OF CREDIT").

THIS STANDBY LETTER OF CREDIT IS IRREVOCABLE AND IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS AND BONA FIDE HOLDERS OF THIS STANDBY LETTER OF CREDIT THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT WILL BE HONORED ON PRESENTATION OF THIS STANDBY LETTER OF CREDIT.

THIS STANDBY LETTER OF CREDIT IS AVAILABLE IN ONE OR MORE DRAFTS AND MAY BE DRAWN HEREUNDER FOR THE ACCOUNT OF THE ACCOUNT PARTY UP TO AN AMOUNT NOT EXCEEDING US$ _____.00 (UNITED STATES DOLLARS _____ AND 00/100) .

THIS STANDBY LETTER OF CREDIT IS DRAWN AGAINST BY PRESENTATION TO US AT OUR OFFICE LOCATED AT THE FOLLOWING ADDRESS:

_____

_____

_____;

OF A DRAFT IN THE FORM OF A DRAWING CERTIFICATE THAT IS SIGNED BY A PURPORTED OFFICER OR AUTHORIZED AGENT OF THE ISO AND DATED THE DATE OF

PRESENTATION CONTAINING THE FOLLOWING STATEMENT IN (1) BELOW ALONG WITH THE APPROPRIATE STATEMENT IN (2) BELOW:

(1) "THE UNDERSIGNED HEREBY CERTIFIES TO [BANK] ("ISSUER"), WITH REFERENCE TO IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO. [------] (THE "STANDBY LETTER OF CREDIT") ISSUED BY ISSUER IN FAVOR OF ISO NEW ENGLAND INC. ("ISO"), THAT

(2) [POSTING ENTITY] HAS FAILED TO PAY THE ISO, IN ACCORDANCE WITH THE TERMS AND PROVISIONS OF THE TARIFF FILED BY THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____.];**OR**

[ISSUER HAS FAILED TO MAINTAIN A MINIMUM LONG-TERM DEBT RATING FROM ANY APPLICABLE RATING AGENCY (OR, IF THE ISSUER DOES NOT HAVE A MINIMUM LONG-TERM DEBT RATING, THEN A MINIMUM CORPORATE RATING) OF "A-" BY STANDARD AND POOR'S , OR "A3" BY MOODY'S OR "A-" BY FITCH, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____. **]; OR**

[**INCLUDE ONLY IN FORM IF LETTER OF CREDIT HAS A FIXED EXPIRATION DATE:]** [AS OF THE CLOSE OF BUSINESS ON _____, 20__ (FILL IN DATE WHICH IS WITHIN 30 DAYS BEFORE THE EXPIRATION DATE OF THE STANDBY LETTER OF CREDIT), [ACCOUNT PARTY] HAS FAILED TO RENEW THE STANDBY LETTER OF CREDIT IN A MANNER ACCEPTABLE TO THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____. **]; OR**

[**INCLUDE ONLY IN FORM IF LETTER OF CREDIT HAS AUTOMATIC RENEWAL LANGUAGE:]** [AS OF THE CLOSE OF BUSINESS ON _____, 20__ (FILL IN DATE WHICH IS WITHIN 30 DAYS BEFORE THE EXPIRATION DATE OF THE STANDBY LETTER OF CREDIT IF NOT AUTORENEWING), WE HAVE BEEN PROVIDED NOTICE FROM [ACCOUNT PARTY] [ISSUER] THAT THE STANDBY LETTER OF CREDIT WILL NOT BE

EXTENDED FOR AN ADDITIONAL ONE (1) YEAR PERIOD, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____.]

IF PRESENTATION OF ANY DRAWING CERTIFICATE IS MADE ON A BUSINESS DAY AND SUCH PRESENTATION IS MADE AT OUR COUNTERS ON OR BEFORE 10:00 A.M. _____ TIME, WE SHALL SATISFY SUCH DRAWING REQUEST ON THE SAME BUSINESS DAY. IF THE DRAWING CERTIFICATE IS RECEIVED AT OUR COUNTERS AFTER 10:00 A.M. _____ TIME, WE WILL SATISFY SUCH DRAWING REQUEST ON THE NEXT BUSINESS DAY. FOR THE PURPOSES OF THIS SECTION, A BUSINESS DAY MEANS A DAY, OTHER THAN A SATURDAY OR SUNDAY, ON WHICH THE FEDERAL RESERVE BANK OF NEW YORK IS NOT AUTHORIZED OR REQUIRED TO BE CLOSED. DISBURSEMENTS SHALL BE IN ACCORDANCE WITH THE INSTRUCTIONS OF THE ISO.

THE FOLLOWING TERMS AND CONDITIONS APPLY:

THIS STANDBY LETTER OF CREDIT SHALL EXPIRE AT THE CLOSE OF BUSINESS [DATE] [AT LEAST 120 DAYS AFTER ISSUANCE FOR NEW POSTING ENTITIES].

[**INCLUDE ONLY IF LETTER OF CREDIT HAS A FIXED EXPIRATION DATE:]** [IF [ACCOUNT PARTY] HAS FAILED TO RENEW THIS STANDBY LETTER OF CREDIT IN A MANNER ACCEPTABLE TO THE ISO, YOU MAY DRAW ON THIS STANDBY LETTER OF CREDIT WITHIN THE THIRTY (30) DAYS PRIOR TO THE EXPIRY DATE BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.]

[**INCLUDE ONLY IF LETTER OF CREDIT IS TO HAVE AUTOMATIC RENEWAL LANGUAGE:]** [IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT IT WILL BE AUTOMATICALLY EXTENDED WITHOUT AN AMENDMENT FOR A (1) YEAR PERIOD BEGINNING ON THE INITIAL EXPIRATION DATE HEREOF AND UPON EACH ANNIVERSARY OF SUCH DATE, UNLESS AT LEAST [THIRTY (30) **OR** SIXTY (60) **OR** NINETY (90)] DAYS PRIOR TO ANY SUCH EXPIRATION DATE WE HAVE SENT YOU, OR THE ACCOUNT PARTY HAS SENT YOU, WRITTEN NOTICE BY

REGULAR AND REGISTERED MAIL OR COURIER SERVICE THAT WE OR THE ACCOUNT PARTY ELECT NOT TO PERMIT THIS LETTER OF CREDIT TO BE SO EXTENDED, AND THAT THIS LETTER OF CREDIT WILL EXPIRE ON ITS THEN CURRENT EXPIRATION DATE. UPON RECEIPT OF SUCH NOTICE, YOU MAY DRAW ON THIS STANDBY LETTER OF CREDIT WITHIN THE THIRTY (30) DAYS PRIOR TO THE THEN RELEVANT EXPIRY DATE BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.]

IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT WE SHALL MAINTAIN A MINIMUM LONG-TERM DEBT RATING (OR, IF WE DO NOT HAVE A MINIMUM LONG-TERM DEBT RATING, THEN A MINIMUM CORPORATE RATING) OF "A-" BY STANDARD AND POOR'S, OR "A3" BY MOODY'S OR "A-" BY FITCH. IN THE EVENT THAT WE ARE RATED BY MULTIPLE RATING AGENCIES, IF ANY APPLICABLE RATING FROM THE RATING AGENCIES FALLS BELOW THE LEVELS LISTED, THEN WE SHALL NOT BE CONSIDERED TO HAVE SATISFIED THIS CONDITION. IN THE EVENT THAT WE DO NOT SATISFY THE CONDITION REQUIRED BY THIS PARAGRAPH, YOU MAY DEMAND PAYMENT FROM US AT THE ADDRESS ABOVE, BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.

THE AMOUNT WHICH MAY BE DRAWN BY YOU UNDER THIS STANDBY LETTER OF CREDIT SHALL BE AUTOMATICALLY REDUCED BY THE AMOUNT OF ANY DRAWINGS HEREUNDER AT OUR COUNTERS. ANY NUMBER OF PARTIAL DRAWINGS ARE PERMITTED FROM TIME TO TIME HEREUNDER.

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY.

THIS STANDBY LETTER OF CREDIT IS NOT TRANSFERABLE OR ASSIGNABLE. THIS STANDBY LETTER OF CREDIT DOES NOT INCORPORATE AND SHALL NOT BE DEEMED MODIFIED, AMENDED OR AMPLIFIED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE ISP, AS DEFINED BELOW) OR (B) IN WHICH THIS STANDBY

LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS STANDBY LETTER OF CREDIT RELATES.

THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE INTERNATIONAL STANDBY PRACTICES ("ISP98") OF THE INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 590, INCLUDING ANY AMENDMENTS, MODIFICATIONS, OR REVISIONS THEREOF (THE "ISP"), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ISP, IN WHICH CASE THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL GOVERN. THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY THE INTERNAL LAWS OF THE COMMONWEALTH OF MASSACHUSETTS TO THE EXTENT THAT THE TERMS ARE NOT GOVERNED BY THE ISP.

THIS STANDBY LETTER OF CREDIT MAY NOT BE AMENDED, CHANGED OR MODIFIED WITHOUT THE EXPRESS WRITTEN CONSENT OF THE ISO AND ISSUER.

WE HEREBY ENGAGE WITH YOU THAT DOCUMENTS DRAWN UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL BE DULY HONORED UPON PRESENTATION AS SPECIFIED AND WE REPRESENT THAT THE ACCOUNT PARTY IS NOT AN AFFILIATE OF THE ISSUER.

PRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS STANDBY LETTER OF CREDIT MAY BE SENT TO US BY COURIER, CERTIFIED MAIL, REGISTERED MAIL, OR FACSIMILE (WITH A CONFIRMING COPY OF SUCH FACSIMILE SENT AFTER THE DRAWING BY CERTIFIED MAIL TO THE ADDRESS SET FORTH BELOW; PROVIDED HOWEVER, THAT THE CONFIRMING COPY SHALL NOT BE A PREREQUISITE FOR US TO HONOR ANY PRESENTATION OTHERWISE MADE IN ACCORDANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT), OR SUCH OTHER ADDRESS AS MAY HEREAFTER BE FURNISHED BY US. OTHER NOTICES CONCERNING THIS STANDBY LETTER OF CREDIT MAY BE SENT BY SIMILAR COMMUNICATIONS FACILITY TO THE RESPECTIVE ADDRESSES SET FORTH BELOW. ALL SUCH NOTICES AND COMMUNICATIONS SHALL BE EFFECTIVE UPON RECEIPT BY THE INTENDED RECIPIENT PARTY.

IF TO THE BENEFICIARY OF THIS STANDBY LETTER OF CREDIT:

ISO NEW ENGLAND INC.
ATTENTION: CREDIT DEPARTMENT
1 SULLIVAN RD. HOLYOKE, MA 01040
FAX: 413-540-4569
EMAIL: CREDITDEPARTMENT@ISO-NE.COM

IF TO THE ACCOUNT PARTY:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

IF TO ISSUER:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

_____ _____

[SIGNATURE] [SIGNATURE]

**ATTACHMENT 3**

**ISO NEW ENGLAND MINIMUM CRITERIA FOR MARKET PARTICIPATION OFFICER CERTIFICATION FORM**

| **Certifying Entity:** | |
|---|---|

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the minimum criteria for market participation requirements set forth in Sections II.A.2 and II.A.3 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity has established or contracted for written policies, procedures, and controls applicable to participation in the New England Markets, approved by Certifying Entity's independent risk management function[1], which provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Certifying Entity is exposed, including, but not limited to, credit risk, liquidity risk, concentration risk, default risk, operation risk, and market risk.

2. Certifying Entity has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets.

3. Certifying Entity has appropriate operating procedures and technical abilities to promptly and effectively respond to all ISO New England communications and directions.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England's minimum criteria for market participation requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

_____
(Signature)

Print Name:_____

Title: _____

Date: _____

[1] As used in this certification, a Certifying Entity's "independent risk management function" can include appropriate corporate persons or bodies that are independent of the Certifying Entity's trading functions, such as a risk management committee, a risk officer, a Certifying Entity's board or board committee, or a board or committee of the Certifying Entity's parent company.

**ATTACHMENT 4**

**ISO NEW ENGLAND ADDITIONAL ELIGIBILITY REQUIREMENTS**

**CERTIFICATION FORM**

| **Certifying Entity:** | |
|---|---|

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the additional eligibility requirements set forth in Section II.A.5 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity is now and in good faith will seek to remain (check applicable box(es)):

   □ an "appropriate person," as defined in section(s) [ ] of the Commodity Exchange Act (7 U.S.C. § 1 *et seq*.) (specify which section(s) of Commodity Exchange Act sections 4(c)(3)(A) through (J) apply)) (if Certifying Entity is relying on section 4(c)(3)(F), it shall accompany this certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the Certifying Entity's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy);

   □ an "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or

   ☐ a "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

2. If at any time Certifying Entity no longer satisfies the criteria in paragraph 1 above, Certifying Entity will immediately notify ISO New England in writing and will immediately cease all participation in the New England Markets.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England's additional eligibility requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

_____
(Signature)

Print Name:_____

Title: _____

Date: _____

**ATTACHMENT 5**

**ISO NEW ENGLAND CERTIFICATE REGARDING CHANGES TO SUBMITTED RISK MANAGEMENT POLICIES FOR FTR PARTICIPATION**

| **Certifying Entity:** | |
|---|---|

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the annual certification requirement for FTR market participation regarding its risk management policies, procedures, and controls set forth in Section II.A.2(b) of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows (check applicable box):

1. □ There have been no changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity's participation in the FTR market.

   OR

2. □ There have been changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity's participation in the FTR market and such changes are clearly identified and attached hereto.*

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England's risk management policy requirements for FTR market participants and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

_____

____

(Signature)

Print Name:_____

Title:

_____

Date:

_____

_____

* As used in this certificate, "clearly identified" changes may include a redline comparing the current written risk management policies, procedures, and controls and the previously submitted written risk management policies, procedures, and controls; or resubmission of the written risk management policies, procedures, and controls with a bulleted list of all changes, including section and/or page numbers.

## ATTACHMENT 6

## MINIMUM CRITERIA FOR MARKET PARTICIPATION

## INFORMATION DISCLOSURE FORM

Date: _____

Prepared by: _____

Customer/Applicant:[1] _____

I, _____, a duly authorized Senior Officer of _____ ("Certifying Entity"), understanding that ISO New England Inc. ("ISO") is relying on this certification provided pursuant to Financial Assurance Policy Section II.A.1(a), hereby certify that I have full authority to bind Certifying Entity and further certify on behalf of Certifying Entity that the information contained herein is true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission:

1. List of all Principals.[2] Please discuss each Principal's relationship with the Certifying Entity and describe each Principal's previous experience related to participation in North American wholesale or retail energy markets or trading exchanges:

[1] Customer and Applicant are each defined in Section II.A of the ISO New England Financial Assurance Policy, Exhibit 1A to Section 1 of the ISO Transmission, Markets, and Services Tariff ("Tariff"). Capitalized terms used but not otherwise defined herein shall have the meaning given to them in the Tariff.

[2] 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 ("FERC"), the Securities and Exchange Commission ("SEC"), the Commodity Futures Trading Commission ("CFTC"), any exchange monitored by the National Futures Association ("NFA"), 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.

2. List all material litigation (criminal or civil) against Certifying Entity or any of the Certifying Entity's Principals, Personnel,[1] or Predecessors,[2] arising out of participation in any wholesale or retail energy market (domestic or international) or trading exchanges in the past ten (10) years:
   *(Enter N/A if not applicable)*
3. List all sanctions issued against or imposed upon Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges where such sanctions were either imposed in the past ten (10) years or, if imposed prior to that, are still in effect. List all known material ongoing investigations regarding Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, imposed by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges:
   *(Enter N/A if not applicable)*

4. Provide a summary of any bankruptcy, dissolution, merger, or acquisition of Certifying Entity in the past ten (10) years (include date, jurisdiction, and other relevant details):
   *(Enter N/A if not applicable)*

5. List all wholesale or retail energy market-related operations in North America where Certifying Entity is currently participating, or, in the past five (5) years, has previously participated other than in the New England Markets (e.g., PJM - FTRs):
   *(Enter N/A if not applicable)*

6. Describe if Certifying Entity or any of Certifying Entity's Principals, Personnel, or any Predecessor of the foregoing ever had its participation or membership in any independent system operator or regional transmission organization (domestic or international) terminated, its registration/membership application denied, or is subject to an existing uncured suspension from participating in the markets of any independent system operator or regional transmission organization (domestic or international), each in the past five (5) years.
   *(Enter N/A if not applicable)*

**If you are currently an active participant and this is your annual submission you do not have to complete Question 7 and can skip to the signature block below. If you are in the process of applying for membership with the ISO you are required to answer the additional questions listed below.**

7. Describe how Certifying Entity plans to fund its operations, including persons or entities providing financing and such person(s)' or entity(ies)' relationship to the Certifying Entity. Include any relationships that may impact Certifying Entity's ability to (a) comply with the time frames to post

[1] Personnel means any person, current or former, responsible for decision making regarding Certifying Entity's transaction of business in the New England Markets, including, without limitation, decisions regarding risk management and trading, or any person, current or former, with access to enter transactions into ISO systems. Disclosures regarding former Personnel shall only be required for when such Personnel was employed by Certifying Entity.

[4] Predecessor shall mean any person or entity whose liabilities, including liabilities arising under the Tariff, have or may have been retained or assumed by Certifying Entity, either contractually, by operation of law or considering all relevant factors, including the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base.

financial assurance and/or pay invoices or other amounts owed to the ISO, each as required by the Tariff; or (b) provide a first priority perfected security interest in required financial assurance to the ISO:

Certifying Entity: _____

By: _____
(Signature)

Print Name: _____

Title: _____

Date: _____

** To satisfy the disclosure requirements above, a Certifying Entity may attach additional materials and may provide the ISO with filings made to the SEC or other similar regulatory agencies that include substantially similar information to that required above, provided that Certifying Entity clearly indicates where the specific information is located in those filings.

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# 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, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, ~~Capacity Performance 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 Supplied 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, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, ~~Capacity Performance 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) The following 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) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.

(iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR 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 steam 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) An Establish Claimed Capability Audit may be performed only by a Generator Asset.

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

(c) For a newly commercial Generator Asset:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within five 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.

(d) 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 five 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.

(e) 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.

(f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.

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

(i) Initiate an Establish 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.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(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.

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

| **Duration Required for an Establish Claimed Capability Audit** | |
|---|---|
| **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 (Electric Storage)<br>Hydraulic Turbine – Other | 2 |
| Hydro-Conventional Daily Pondage<br>Hydro-Conventional Run of River<br>Hydro-Conventional Weekly | 2 |
| Wind<br>Photovoltaic<br>Fuel Cell | 2 |
| Other Electric Storage (Excludes Hydraulic Turbine - Reversible) | 2 |

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

**III.1.5.1.3. Seasonal Claimed Capability Audits.**

(a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.

(b) 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).

(c) 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.

(d) Except as provided in Section III.1.5.1.3(n) 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.

(e) 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.

(f) 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 fifth 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.

(g) 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.

(h) 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(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(i) 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.

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

| **Duration Required for a Seasonal Claimed Capability Audit** | |
|---|---|
| **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 (Electric Storage)<br>Hydraulic Turbine-Other | 2 |
| Hydro-Conventional Weekly | 2 |
| Fuel Cell | 1 |
| Other Electric Storage (Excludes Hydraulic Turbine - Reversible) | 2 |

(k) 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.

(l) 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.

(m) 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.

(n) 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(f).

(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(d)(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(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

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

**III.1.5.1.3.1 Seasonal DR Audits.**

(a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

(b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.

(c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of April through November;

(d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of December through March.

(e) A Seasonal DR Audit may be performed either:

(i) At the request of a Market Participant as described in subsection (f) below; or

(ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.

(f) If a Market Participant requests a Seasonal DR Audit:

(i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.

(ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.

(iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

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

(g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth 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 DR Audit.

(iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.

(iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

(h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.

(i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.

(j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

(k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.

(l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.

(m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

(n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.

(o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

**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 either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both 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 for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset 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 for a Generator Asset 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) The 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) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) For Generator Assets, 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.

(iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

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

| **Duration Required for an ISO-Initiated Claimed Capability Audit** | |
|---|---|
| **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 (Electric Storage)<br>Hydraulic Turbine – Other | 2 |
| Hydro-Conventional Daily Pondage<br>Hydro-Conventional Run of River<br>Hydro-Conventional Weekly | 2 |
| Wind<br>Photovoltaic<br>Fuel Cell | 2 |
| Other Electric Storage (Excludes Hydraulic Turbine – Reversible) | 2 |
| Demand Response Resource | 1 |

(g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource 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 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 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 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(f).

(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 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 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.

**III.1.5.3 Reactive Capability Audits.**

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

(i) A lagging Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to provide reactive power to the transmission system at a specified real power output or consumption.

(ii) A leading Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to absorb reactive power from the transmission system at a specified real power output or consumption.

(b) The ISO shall develop a list of Reactive Resources that must conduct Reactive Capability Audits. The list shall include Reactive Resources that: (i) have a gross individual nameplate rating greater than 20 MVA; (ii) are directly connected, or are connected through equipment designed primarily for delivering real or reactive power to an interconnection point, to the transmission system at a voltage of 100 kV or above; and (iii) are not exempted from providing voltage control by the ISO. Additional criteria to be used in adding a Reactive Resource to the list includes, but is not limited to, the effect of the Reactive Resource on System Operating Limits, Interconnection Reliability Operating Limits, and local area voltage limits during the following operating states: normal, emergency, and system restoration.

(c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall perform both a lagging Reactive Capability Audit and a leading Reactive Capability Audit.

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

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

(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.

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

(i) there is a change in the Reactive Resource that may affect the reactive power capability of the Reactive Resource;

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

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

(h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may 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 Transmission Constraint Penalty Factors.**

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is $10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is $30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any transmission constraint is $30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

**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. The ISO shall use a joint optimization process to serve Day-Ahead Market energy requirements and Day-Ahead Ancillary Services requirements, as described in Section III.1.10.8(a).

(b) [Reserved].

(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 LMP-Based Energy Pricing**.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the 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 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 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 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.1.7.9A Day-Ahead Ancillary Services Prices.**

The prices paid by the ISO for the provision of Day-Ahead Ancillary Services in the New England Markets will reflect Day-Ahead Ancillary Services clearing prices determined by the ISO in accordance with the ISO New England Filed Documents.

**III.1.7.10 Other Transactions.**

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.

**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 Seasonal DR Audit Value of an Active Demand Capacity Resource.**

(a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through

November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.

(b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

**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 endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. 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 Ramping.**

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to potential referral under Section III.A.19.

**III.1.7.19 Real-Time Reserve Designation**.

The ISO shall determine the Real-Time Reserve Designation for each eligible Resource in accordance with this Section III.1.7.19. The Real-Time Reserve Designation shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve.

**III.1.7.19.1 Eligibility.**

To be eligible to receive a Real-Time Reserve Designation, a Resource must meet all of the criteria enumerated in this Section III.1.7.19.1. A Resource that does not meet all of these criteria is not eligible to provide Operating Reserve and will not receive a Real-Time Reserve Designation.

(1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.

(2) The Resource must not be part of the first contingency supply loss.

(3) The Resource must not be designated as constrained by transmission limitations.

(4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)

(5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

**III.1.7.19.2 Calculation of Real-Time Reserve Designation.**

**III.1.7.19.2.1 Generator Assets.**

**III.1.7.19.2.1.1 On-line Generator Assets.**

The Manual Response Rate used in calculations in this section shall be the lesser of the Generator Asset's offered Manual Response Rate and its audited Manual Response Rate as described in Section III.1.5.2.

(a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Non-Spinning Reserve shall be zero. For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit).

(c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

**III.1.7.19.2.1.2 Off-line Generator Assets.**

For an off-line Generator Asset that is not a Fast Start Generator, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).

(c) **Thirty-Minute Operating Reserve.** For an off-line Fast Start Generator, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Fast Start Generator's Offered CLAIM30, its CLAIM30, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Thirty-Minute Operating Reserve shall be zero, except during the last thirty minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Thirty-Minute Operating Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires), minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Fast Start Generator pursuant to subsection (b) above.

**III.1.7.19.2.2 Dispatchable Asset Related Demand.**

**III.1.7.19.2.2.1 Storage DARDs.**

(a) **Ten-Minute Spinning Reserve.** For a Storage DARD, Ten-Minute Spinning Reserve shall be calculated as the absolute value of the amount of current telemetered consumption.

(b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.

(c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

**III.1.7.19.2.2.2 Dispatchable Asset Related Demand Other Than Storage DARDs.**

(a) **Ten-Minute Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit). For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit).

(c) **Thirty-Minute Operating Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (a) above. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Non-Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (b) above.

**III.1.7.19.2.3 Demand Response Resources.**

For a Demand Response Resource that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2.

**III.1.7.19.2.3.1 Dispatched.**

(a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be

calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction). For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction).

(c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within thirty minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction) minus the Ten-Minute Spinning Reserve quantity calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

**III.1.7.19.2.3.2 Non-Dispatched.**

For a Demand Response Resource that is not being dispatched that is not a Fast Start Demand Response Resource, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Demand Response Resource's Offered CLAIM10, its CLAIM10, and its Maximum Reduction.

(c) **Thirty-Minute Operating Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Demand Response Resource's Offered CLAIM30, its CLAIM30, and its Maximum Reduction, minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Demand Response Resource pursuant to subsection (b) above.

**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 Resources 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, consumption, or demand reduction levels of Generator Assets, DARDs, 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, 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.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands 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.1.7.21 SATOA Participation in Markets:** A Node will be established for each SATOA. A Market Participant's market activity, transactions, and actions taken at a SATOA's Node and a SATOA's participation in the New England Markets shall be limited to those necessary to consume or inject energy from or to PTF for any period, magnitude, and duration identified as necessary to: (1) address the applicable system needs or provide the transmission function for which the SATOA was selected as the preferred solution; or (2) as specified in the ISO New England Operating Documents, avoid or mitigate Load Shedding after all available Dispatchable Resources that can effectively provide relief to avoid or mitigate the Load Shedding have been dispatched.

**III.1.8 Day-Ahead Ancillary Services and Forecast Energy Requirement.**

**III.1.8.1 Day-Ahead Ancillary Services Offers.**

Market Participants may submit Day-Ahead Ancillary Services Offers for the Operating Day in the Day-Ahead Ancillary Services Market as specified in this Section III.1.8.1.

(a) Each Day-Ahead Ancillary Services Offer shall be associated with a specific Generator Asset, Demand Response Resource, or DARD for which the Market Participant has submitted a corresponding Supply Offer, Demand Reduction Offer, or Demand Bid in the Day-Ahead Energy Market for the same hour of the Operating Day.

(b) Each Day-Ahead Ancillary Services Offer shall specify: (i) the hour of the Operating Day for which the Day-Ahead Ancillary Services Offer applies; (ii) product-specific offer prices, in $/MWh, that are greater than or equal to zero for the Day-Ahead Ancillary Services; and (iii) a single offer quantity, in MWh, that is greater than or equal to zero. The offer prices for the Day-Ahead Ancillary Services shall not exceed the Forecast Energy Requirement Penalty Factor as specified in Section III.2.6.2(d) of this Market Rule 1. The offer quantity shall not exceed the Economic Maximum Limit specified in the associated Supply Offer, the Maximum Reduction specified in the associated Demand Reduction Offer, or the Maximum Consumption Limit specified in the associated Demand Bid.

(c) As part of its Day-Ahead Ancillary Services Offer, a Market Participant is permitted to specify a Maximum Daily Award Limit quantity, in MWh, that is greater than or equal to zero.

(d) For each hour of the Operating Day, a Market Participant may submit only one Day-Ahead Ancillary Services Offer associated with a specific Generator Asset, Demand Response Resource, or DARD.

(e) Day-Ahead Ancillary Services Offers shall be submitted by the offer submission deadline for the Day-Ahead Market specified in Section III.1.10.1A of this Market Rule 1. A Day-Ahead Ancillary Services Offer shall not remain in effect for subsequent Operating Days.

**III.1.8.2 Day-Ahead Ancillary Services Strike Price.**

(a) For each hour of the Operating Day, the ISO shall specify the Day-Ahead Ancillary Services Strike Price in $/MWh. The value of the Day-Ahead Ancillary Services Strike Price represents an amount that is the greater of (i) $10/MWh greater than a forecast of the expected hourly Real-Time Hub Price for such hour of the Operating Day and (ii) zero.

(b) The forecast used to determine the Day-Ahead Ancillary Services Strike Price shall be based on a publicly-available forecasting algorithm developed by the ISO. The ISO shall describe the publicly-available forecasting algorithm to Market Participants and shall periodically review and assess the efficacy of the forecasting algorithm. The ISO shall notify stakeholders of any potential revisions to the ISO's forecasting algorithm prior to implementing such revisions.

(c) In the event that the ISO is not able to utilize the ISO-developed forecasting algorithm described in subsection (b) above due to hardware, software, or telecommunications problems, human error, or exigent circumstances not contemplated by this market rule, the ISO shall determine the Day-Ahead Ancillary Services Strike Price using the best forecast available and shall disclose the use of such substitute forecast to Market Participants as soon as practicable.

**III.1.8.3 Day-Ahead Flexible Response Services Demand Quantities.**

The Day-Ahead Ancillary Services Market shall endeavor to procure the Day-Ahead Flexible Response Services Demand Quantities specified in this Section III.1.8.3.

(a) For each hour of the Operating Day, the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the Ten-Minute Spinning Reserve Requirement projected Day-Ahead.

(b) For each hour of the Operating Day, the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the Ten-Minute Reserve Requirement projected Day-Ahead.

(c) For each hour of the Operating Day, the Day-Ahead Minimum Total Reserve Demand Quantity shall be equal to the Minimum Total Reserve Requirement projected Day-Ahead.

(d) For each hour of the Operating Day, the Day-Ahead Total Reserve Demand Quantity shall be equal to the Total Reserve Requirement projected Day-Ahead.

**III.1.8.4 Forecast Energy Requirement Demand Quantity.**

For each hour of the Operating Day, the Forecast Energy Requirement Demand Quantity shall be equal to the ISO forecast for the total load in the New England Control Area produced pursuant to Section III.1.10.1A(h) of this Market Rule 1.

**III.1.9 Pre-scheduling.**

**III.1.9.1 Offer and Bid Caps and Cost Verification for Offers and Bids.**

**III.1.9.1.1 Cost Verification of Resource Offers.**

The incremental energy values of Supply Offers and Demand Response Resources above $1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or $1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than $1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be

performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to $1,000/MWh, then the adjusted offer for the Resource is set at $1,000/MWh;

(ii) If the Reference Level value is greater than $1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

**III.1.9.1.2 Offer and Bid Caps.**

(a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at $2,000/MWh.

(b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.

(c) Supply Offers and Demand Reduction Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

(d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.

(e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

**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 Generator Asset 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 the Day-Ahead Market and a Real-Time Energy Market.

(b) The Day-Ahead Market shall enable Market Participants to purchase and sell energy and sell ancillary services 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 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 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 Generator Assets or Demand Response 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 or Demand Reduction Offers.

**III.1.10.1A Energy and Day-Ahead Ancillary Services Market Scheduling**.
Market Participants may submit offers and bids in the Day-Ahead Market until 10:30 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) **Locational Demand Bids –** 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 applicable Day-Ahead Price, (ii) hourly schedules for Resources 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 Demand Bid Cap and Virtual Cap.

(b) **External Transactions –** All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets 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. 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) In the Day-Ahead Energy Market, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) In the Day-Ahead Energy Market, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction 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.

(c) **Generator Asset Supply Offers –** Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

(i) Shall specify the Resource and 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 prices and quantities in a Block may each vary on an hourly basis;

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

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type 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 Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including 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 an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and

(vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.

**(d) DARD Demand Bids –** Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including 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;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

(iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers –** Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.

(f) **Demand Reduction Threshold Price –** The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

(a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.

(c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

(d) A historic threshold price $P_{th}$ shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th}X - \frac{FPI_c}{FPI_h}$$

where $FPI_h$ is the historic fuel price index for the same month of the previous year, and $FPI_c$ is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction 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 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, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) **Load Estimate** – 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) **Prorated Supply** – 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) **Prorated Demand** – 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) **Virtuals** – 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.

(l) **Day-Ahead Ancillary Services Offers** – Market Participants selling into the New England Markets from Generator Assets or Demand Response Resources or participating in the New England Markets with DARDs, and that have submitted Supply Offers, Demand Reduction Offers, or Demand Bids for the following Operating Day, as described in subsections (c), (d), and (e) of this Section III.1.10.1A, may submit Day-Ahead Ancillary Services Offers for the following Operating Day. Day-Ahead Ancillary Services Offers shall be submitted to the ISO in accordance with Section III.1.8.1 of this Market Rule 1.

**III.1.10.2 Pool-Scheduled Resources.**

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs or Demand Response

Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume 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 supply or consumption, ancillary services, 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 and ancillary services 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 Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids, ancillary services offers and requirements, and the Forecast Energy Requirement Demand Quantity.

(c) Market Participants offering energy from 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) 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. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD 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. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource shall not be Self-Scheduled.

**III.1.10.4 External Resources**.

Market Participants with External Resources may submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

**III.1.10.5 Dispatchable Asset Related Demand.**

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

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

(ii) 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;

(iii) abide by the ISO maintenance coordination procedures; and

(iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

**III.1.10.6 Electric Storage**

A storage facility is a facility that is capable of receiving electricity and storing the energy for later injection of electricity into the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

(i) comprise one or more storage facilities at the same point of interconnection;

(ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;

(iii) be directly metered;

(iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;

(v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;

(vi) settle its injection of electricity to the grid as a Generator Asset and any receipt of electricity from the grid as a DARD;

(vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and

(viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility; and

(ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and

(iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.

(c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility;

(ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;

(iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;

(iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;

(v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;

(vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;

(vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and

(viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).

(d) In clearing the Day-Ahead Energy Market, the ISO will respect Electric Storage Facility Initial State of Charge, Round Trip Efficiency, Maximum State of Charge, and Minimum State of Charge.

(e) A storage facility incapable of receiving and storing electricity from the grid may participate in the New England Markets as a Continuous Storage Facility, so long as that facility satisfies all Continuous Storage Facility registration and participation requirements that are not solely related to consumption capability. Notwithstanding Section III.1.10.6(a), Section III.1.10.6(c), and any other related provisions, such non-consuming storage facilities shall not be required to:

(i) be capable of consuming at least 0.1 MW from the grid; or

(ii) be capable of modifying consumption responsive to Dispatch Instructions.

(f) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:

a. A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.

b. A storage facility's charging energy shall not qualify as, or be billed to, a Storage DARD if that facility's charging energy is included in another Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging energy.

c. The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.

d. Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.

(v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.

(g) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.

(h) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.

(i) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered

and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

(j) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.

(k) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

**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 procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.

(d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID 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, as determined in accordance with Section III.12.4, that experienced price separation in the Annual Capacity Auction as determined in accordance with Section III.15.4.2.2(j) of Market Rule 1;

(2) The External Transaction is directly associated with an Export Offer Segment that did not receive a Capacity Supply Obligation in the Annual Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the unobligated Export Offer Segment;

(3) The External Node associated with the unobligated Export Offer Segment 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) Annual Capacity Auction 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 Offer Segment that did not receive a Capacity Supply Obligation in the Annual Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the unobligated Export Offer Segment;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Offer Segment 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 or Annual 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 Annual Capacity Auction 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 Annual Capacity Auction Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and Annual Capacity Auction 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 Transaction Scheduling**.

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 15-minute 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 e-Tag ID 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 the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, permit the transaction to be scheduled.

**III.1.10.8 Scheduling Considerations.**

(a) In scheduling the Day-Ahead Market, the ISO shall use its best efforts to determine the security-constrained economic commitment and dispatch that jointly optimizes: (i) Demand Bids, Decrement Bids, Demand Reduction Offers, Supply Offers, Increment Offers, and External Transactions, for energy; (ii) Day-Ahead Ancillary Services Offers to satisfy the Day-Ahead Flexible Response Services Demand Quantities; and (iii) Supply Offers, Demand Reduction Offers, External Transactions, and Day-Ahead Ancillary Services Offers to satisfy the Forecast Energy Requirement Demand Quantity.

In making the determination specified in this subsection (a), the ISO shall take into account, as applicable: (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 ancillary services; (vi) the operational capabilities of any Resource to adjust the output, consumption, or demand reduction within the operating characteristics and parameters specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, or Demand Bid and any audited values of such operating characteristics and parameters; (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.

In scheduling the Day-Ahead Market, the following limitations shall apply:

(i) For purposes of satisfying the Day-Ahead Flexible Response Services Demand Quantities specified in Sections III.1.8.3(a) through (d), the ISO shall not take into account a Day-Ahead Ancillary Services Offer unless the Generator Asset, Demand Response Resource, or DARD associated with the Day-Ahead Ancillary Services Offer meets the eligibility requirements enumerated in Section III.1.7.19.1.

(ii) For purposes of satisfying the Forecast Energy Requirement Demand Quantity specified in Section III.1.8.4, the ISO shall not take into account a Day-Ahead Ancillary Services Offer unless the offer is associated with a Generator Asset or Demand Response Resource that meets the following conditions:

(1) The Generator Asset or Demand Response Resource is, for the applicable hour, either scheduled for energy in the Day-Ahead Energy Market or is a Fast Start Generator or Fast Start Demand Response Resource.

(2) The Generator Asset or Demand Response Resource is not designated as constrained by transmission limitations, as described in Section III.1.7.19.1(3).

(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 and ancillary services 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 Market cannot 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. The ISO shall use its best efforts to determine the least-cost means to satisfy any remaining reliability requirements of the New England Control Area for the Operating Day.

(d) Market Participants shall pay and be paid for the quantities of energy and ancillary services scheduled in the Day-Ahead Market based upon applicable 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 Resources and to direct that schedules be changed to address an actual or potential 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 Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. 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) During the Re-Offer Period, Market Participants may submit revisions to the price of 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 request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. 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(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) 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 Generator Assets), and the quantity and price pairs of its Blocks may be modified.

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

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

(e) 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. A Market Participant may not request to Self-Schedule a Demand Response Resource. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

(f) 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(c), 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 at a specified value. 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 at or above the requested amount for the hour in question.

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

(i) 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 or Consumption and Demand Reduction.**

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource 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, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) 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; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) 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 Dispatchable Resources.**

With the exception of Settlement Only Resources, Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, and nuclear-powered Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

(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 Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable 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 for a Dispatchable Resource 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 Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind, solar, and hydro Intermittent Power Resources that are not Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

(i) A Market Participant may elect, but is not required, to have a wind, solar, or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.

(ii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.

(f) The ISO may request that dual-fuel Generator Assets 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-fuel Generator Assets 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-fuel Generator Assets 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 Dispatchability Requirements for Intermittent Power Resources.**

(a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.

(b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redeclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

(c) Wind and solar Generator Assets that are not Settlement Only Resources shall electronically transmit meteorological and forced outage data, as specified below, to the ISO, over a secure network, using the protocol specified in the ISO Operating Documents, for the development and deployment of wind and solar power production forecasts.

Wind Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

(i) at least once every 30 seconds: wind speed, and wind direction;

(ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, and standard deviation of ambient air relative humidity;

(iii) at least once every 5 minutes: Real-Time High Operating Limit, Wind High Limit, wind turbine counts; and

(iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Wind Plant Future Availability.

Solar Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

(i) at least once every 30 seconds: irradiance;

(ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, standard deviation of ambient air relative humidity, wind speed, and wind direction;

(iii) at least once every 5 minutes: Real-Time High Operating Limit, and Solar High Limit; and

(iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Solar Plant Future Availability.

**III.1.11.6 Non-Dispatchable Resources.**

Non-Dispatchable Resources are subject to the following requirements:

(a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource 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.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

**III.13.5. Bilateral Contracts in the Forward Capacity Market.**

Market Participants shall be permitted to enter into Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, and Capacity Load Obligation Bilaterals ~~and Capacity Performance Bilaterals~~ in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

**III.13.5.1. Capacity Supply Obligation Bilaterals.**

Capacity Supply Obligation Bilaterals are available for monthly periods. The qualification of resources subject to a Capacity Supply Obligation Bilateral is determined in the same manner as the qualification of resources is determined for reconfiguration auctions as specified in Section III.13.4.2.

A resource having a Capacity Supply Obligation seeking to shed that obligation (Capacity Transferring Resource) may enter into a bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part (Capacity Supply Obligation Bilateral), to a resource, or portion thereof, having Qualified Capacity for that Capacity Commitment Period that is not already obligated (Capacity Acquiring Resource), subject to the following limitations.

(a) A Capacity Supply Obligation Bilateral must be coterminous with a calendar month.

(b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the monthly Capacity Supply Obligation of the Capacity Transferring Resource. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the amount of unobligated Qualified Capacity (that is, Qualified Capacity as determined in the most recent Forward Capacity Auction or reconfiguration auction qualification process that is not subject to a Capacity Supply Obligation) of the Capacity Acquiring Resource during the month covered by the Capacity Supply Obligation Bilateral, as determined in the qualification process for the most recent Forward Capacity Auction or annual reconfiguration auction prior to the submission of the Capacity Supply Obligation Bilateral to the ISO.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource's unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.

(d) [Reserved.]

(e) [Reserved.]

(f) [Reserved.]

(g) [Reserved.]

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant Obligation Month.

(j) A resource that is not expected to achieve FCM Commercial Operation prior to the end of a given Obligation Month in accordance with posted schedules may not submit a transaction as a Capacity Acquiring Resource for that month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a Capacity Supply Obligation Bilateral in an amount up to the absolute value of its Capacity Supply Obligation.

**III.13.5.1.1. Process for Approval of Capacity Supply Obligation Bilaterals.**

**III.13.5.1.1.1. Timing of Submission and Prior Notification to the ISO.**

The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

**III.13.5.1.1.2. Application.**

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, in $/kW-month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

**III.13.5.1.1.3. ISO Review.**

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral, and shall reject the Capacity Supply Obligation Bilateral if any of the provisions of this Section III.13.5.1 are not met. For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.

(b) After the close of the relevant submittal window, each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards will remain satisfied if the capacity associated with the Capacity Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO's reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation outage information, and will include transmission security studies. The ISO will review all confirmed Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. The ISO shall obtain and consider information from the Local Control Center regarding whether the Capacity Supply Obligation of the Capacity Transferring Resource is needed for local system conditions and whether it is adequately replaced by the Acquiring Resource.

The ISO will approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. If multiple Capacity Supply Obligation Bilaterals are submitted between the same resources, they may be reviewed together as one transaction and the most recent confirmation time among the related transactions will be used to determine the review order of the grouped transaction. Transactions that cannot meet the applicable reliability needs will only be accepted or rejected in their entirety and the resources will not be accepted or rejected in part for purposes of that transaction. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected for reliability reasons the Lead Market Participant or Project Sponsor, as appropriate, for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the reliability need prompting such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

**III.13.5.1.1.4. Approval.**

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply Obligation of the Capacity Acquiring Resource shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

**III.13.5.2. Capacity Load Obligations Bilaterals.**

A Market Participant having a Capacity Load Obligation seeking to shed that obligation ("Capacity Load Obligation Transferring Participant") may enter into a bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone ("Capacity Load Obligation Bilateral") to any Market Participant seeking to acquire a Capacity Load Obligation ("Capacity Load Obligation Acquiring Participant"). A Capacity Load Obligation Bilateral must be in whole calendar month increments, may not exceed one year in duration, and must begin and end within the same Capacity Commitment Period. A Capacity Load Obligation Transferring Participant will be permitted to transfer, and a Capacity Load Obligation Acquiring Participant will be permitted to acquire, a Capacity Load Obligation if after entering

into a Capacity Load Obligation Bilateral and submitting related information to the ISO within the specified submittal time period, the ISO approves such Capacity Load Obligation Bilateral.

**III.13.5.2.1. Process for Approval of Capacity Load Obligation Bilaterals.**

**III.13.5.2.1.1. Timing.**

Either the Capacity Load Obligation Transferring Participant or the Capacity Load Obligation Acquiring Participant may submit a Capacity Load Obligation Bilateral to the ISO. All Capacity Load Obligation Bilaterals must be submitted to the ISO in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial daily settlements of payments and charges associated with the Forward Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 pm on the first Business Day of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

**III.13.5.2.1.2. Application.**

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following : (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

**III.13.5.2.1.3. ISO Review.**

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section II.13.5.2 are not met.

**III.13.5.2.1.4. Approval.**

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral and the Capacity Load

Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral.

**III.13.5.3.** **[Reserved.]~~Capacity Performance Bilaterals.~~**

~~A resource's Capacity Performance Score during a Capacity Scarcity Condition may be adjusted by entering into a Capacity Performance Bilateral as described in this Section III.13.5.3.~~

**~~III.13.5.3.1. Eligibility.~~**

~~If a resource has a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five-minute interval so long as both resources were subject to the same Capacity Scarcity Condition.~~

**~~III.13.5.3.2. Submission of Capacity Performance Bilaterals.~~**

~~The Lead Market Participant for a resource having a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition may submit a Capacity Performance Bilateral to the ISO assigning all or a portion of its Capacity Performance Score for that interval to another resource, subject to the eligibility requirements specified in Section III.13.5.3.1. The Capacity Performance Bilateral must be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score.~~

**~~III.13.5.3.2.1. Timing.~~**

~~A Capacity Performance Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the month associated with the Capacity Performance Bilateral, a Capacity Performance Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Capacity Performance Bilateral may be revised by the parties to the transaction throughout the resettlement process).~~

**~~III.13.5.3.2.2. Application.~~**

~~The submission of a Capacity Performance Bilateral to the ISO shall include the following: (i) the resource identification number for the resource transferring its Capacity Performance Score; (ii) the resource identification number for the resource receiving the Capacity Performance Score; (iii) the MW~~

~~amount of Capacity Performance Score being transferred; (iv) the specific five-minute interval or intervals for which the Capacity Performance Bilateral applies.~~

~~**III.13.5.3.2.3. ISO Review.**~~

~~The ISO shall review the information provided in submission of the Capacity Performance Bilateral, and shall reject the Capacity Performance Bilateral if any of the provisions of this Section III.13.5.3 are not met.~~

~~**III.13.5.3.3. Effect of Capacity Performance Bilateral.**~~

~~A Capacity Performance Bilateral does not affect in any way either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Capacity Performance Bilateral is to modify the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Conditions subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments as described in Section III.13.7.2.~~

**III.13.5.4 Annual Reconfiguration Transactions.**

Annual Reconfiguration Transactions are available for annual reconfiguration auctions for Capacity Commitment Periods beginning on or after June 1, 2020, except that Annual Reconfiguration Transactions are not available for the first annual reconfiguration auction for the Capacity Commitment Period beginning on June 1, 2020.

**III.13.5.4.1 Timing of Submission.**

The Lead Market Participant or Project Sponsor for either a Capacity Transferring Resource or a Capacity Acquiring Resource may submit an Annual Reconfiguration Transaction to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Annual Reconfiguration Transactions as soon as practicable after the issuance of Forward Capacity Auction results. An Annual Reconfiguration Transaction must be confirmed by the party other than the party submitting the Annual Reconfiguration Transaction to the ISO no later than the end of the relevant submittal window.

**III.13.5.4.2 Components of an Annual Reconfiguration Transaction.**

The submission of an Annual Reconfiguration Transaction must include the following:

1. the resource identification number of the Capacity Transferring Resource;
2. the applicable Capacity Commitment Period;
(3) the resource identification number of the Capacity Acquiring Resource, and;

3. a price ($/kW-month), quantity (MW) and Capacity Zone, to be used in settling the Annual Reconfiguration Transaction.

The maximum quantity of an Annual Reconfiguration Transaction is the higher of:

(1) the Capacity Transferring Resource's maximum demand bid quantity determined pursuant to Section III.13.4.2.2(b), less the quantity of any previously confirmed Annual Reconfiguration Transactions, and;

(2) the Capacity Acquiring Resource's maximum supply offer quantity determined pursuant to Section III.13.4.2.1.1, less the quantity of any previously confirmed Annual Reconfiguration Transactions.

An Annual Reconfiguration Transaction may not be submitted unless the maximum demand bid quantity and maximum supply offer quantity are each greater than zero.

Each Annual Reconfiguration Transaction is limited to a single Capacity Acquiring Resource and a single Capacity Transferring Resource.

If any demand bid of a Capacity Transferring Resource or supply offer of a Capacity Acquiring Resource that is associated with an Annual Reconfiguration Transaction is rejected for reliability reasons pursuant to Section III.13.2.2(c) or Section III.13.4.2.1.5, respectively, the Annual Reconfiguration Transaction is cancelled.

**III.13.5.4.3 Settlement of Annual Reconfiguration Transactions.**

Annual Reconfiguration Transactions are settled on a daily basis during the applicable Capacity Commitment Period. The total of the daily payment amounts for the month is equal to the transaction quantity multiplied by the difference between the annual reconfiguration auction clearing price and the transaction price. If the payment amount is positive, payment is made to the Lead Market Participant with the Capacity Transferring Resource and charged to the Lead Market Participant with the Capacity Acquiring Resource. If the payment amount is negative, payment is made to the Lead Market Participant with the Capacity Acquiring Resource and charged to the Lead Market Participant with the Capacity Transferring Resource.

**III.13.7. Performance, Payments and Charges in the FCM.**

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

**III.13.7.1. Capacity Base Payments**.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1.

**III.13.7.1.1. Payments and Charges Reflecting Capacity Supply Obligations.**

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.13.7.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Forward Capacity Auction**. For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated

with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

(d) **Substitution Auctions.** For a resource whose offer or bid has cleared in a substitution auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the substitution auction clearing price. Notwithstanding the foregoing, the monthly capacity charge for a demand bid cleared at a substitution auction clearing price above its bid price shall be calculated using its bid price.

**III.13.7.1.3. Export Capacity.**

If there are any Export Bids or Administrative Export De-List Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows.

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$ ] x Cleared MWs of Export Bid or Administrative Export De-List Bid]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$ ] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.5.2.

**III.13.7.1.4. [Reserved.]**

**III.13.7.2 Capacity Performance Payments.**

**III.13.7.2.1 Definition of Capacity Scarcity Condition.**

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

**III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.**

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.13.7.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition

shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource or Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.13.7.2.2(c), for any On-Peak Demand Resource or Seasonal Peak Demand Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.13.7.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(i) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource

was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(ii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

(e) A Distributed Energy Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Metered Quantity for Settlement and Reserve Quantity for Settlement of all the components of its constituent Distributed Energy Resource Aggregations; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Based on the Real-Time operational coordination, the resource must follow any distribution system limitation and update its physical parameters accordingly. The Actual Capacity Provided cannot be less than zero.

(i) The Real-Time demand reduction of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled

curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

**III.13.7.2.3 Capacity Balancing Ratio.**

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

provided, however, that the Capacity Balancing Ratio shall not exceed a value of 1.0.

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

**III.13.7.2.4 Capacity Performance Score.**

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

**III.13.7.2.5 Capacity Performance Payment Rate.**

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025, the Capacity Performance Payment Rate shall be $5455/MWh. For the period beginning on June 1, 2025 and ending on August 31, 2026, the Capacity Performance Payment Rate shall be $9337/MWh. Thereafter, the Capacity Performance Payment Rate shall be $3500/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

**III.13.7.2.6 Calculation of Capacity Performance Payments.**

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

**III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.**

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

**III.13.7.3.1 Monthly Stop-Loss.**

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the

product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month).

**III.13.7.3.2 Annual Stop-Loss.**

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (FCAcp – FCAsp) – (12 months x FCAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

**III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments.**

For ~~each type of~~ Capacity Scarcity Condition<u>s,</u> as described in Section III.13.7.2.1 ~~and for each Capacity Zone~~, the ISO shall allocate deficient or excess Capacity Performance Payments as described in

subsections (a), ~~and~~ (b), and (c) below. ~~Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.~~

(a) If the sum of all Capacity Performance Payments to all resources subject to ~~the~~ a Capacity Scarcity Condition ~~in the Capacity Zone~~ in an Obligation Month is positive, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the deficiency ~~will~~ shall be charged to resources in proportion to the sum of each such resource's ~~Capacity Supply Obligation~~positive Capacity Performance Score for the Obligation Month~~, excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month and excluding any resource, or portion thereof, consisting of Energy Efficiency measures. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(a)~~.

(b) If the sum of all Capacity Performance Payments to all resources subject to ~~the~~ a Capacity Scarcity Condition ~~in the Capacity Zone~~ in an Obligation Month is negative, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the excess ~~will~~ shall be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess ~~will~~ shall be further allocated to other resources in the same manner as described in this Section III.13.7.4(b).

(c) If a deficiency of Capacity Performance Payments exists due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the deficiency shall be charged to all resources subject to a Capacity Scarcity Condition in an Obligation Month that have not reached their stop-loss limit (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. If the charge described in Section III.13.7.4(a) or the charge described in this Section III.13.7.4(c) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss limit described in Section III.13.7.3 will be applied

to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(c).

**III.13.7.5. Charges to Market Participants with Capacity Load Obligations.**

**III.13.7.5.1. Calculation of Capacity Charges Prior to June 1, 2022.**

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning prior to June 1, 2022. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month may also receive a failure to cover credit equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone, and; (b) the sum of all failure to cover charges in the Capacity Zone calculated pursuant to Section III.13.3.4(b), divided by total Capacity Load Obligation in the Capacity Zone.

**III.13.7.5.1.1. Calculation of Capacity Charges On and After June 1, 2022.**

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning on or after June 1, 2022. For purposes of this Section III.13.7.5.1.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in subsection (b) of Sections III.13.7.5.1.1.1 through III.13.7.5.1.1.9 will be divided by the number of days in the month to derive a daily settlement value.

**III.13.7.5.1.1.1 Forward Capacity Auction Charge.**

The FCA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone FCA Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone FCA Costs, for each Capacity Zone, are the Total FCA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total FCA Costs are the sum of, for all Capacity Zones, (i) Capacity Supply Obligations in each zone (the total obligation awarded to or shed by resources in the Forward Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.13.7.5.1.1.6 and excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) multiplied by the applicable clearing price from the auction in which the obligation was awarded to (or shed by) the resource, and (ii) the difference between the bid price and the substitution auction clearing price that was not included in the capacity charge pursuant to the second sentence of Section III.13.7.1.1(d). Capacity Supply Obligations awarded to Proxy De-List Bids in the primary auction, or shed by demand bids entered into the substitution auction on behalf of a Proxy De-List Bid, are excluded from Total FCA Costs.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

**III.13.7.5.1.1.2 Annual Reconfiguration Auction Charge.**

The total annual reconfiguration auction charge, for each Capacity Zone and each associated annual reconfiguration auction, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone Annual Reconfiguration Auction Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone Annual Reconfiguration Auction Costs, for each Capacity Zone, are the Total Annual Reconfiguration Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total Annual Reconfiguration Auction Costs are the sum, for all Capacity Zones and each associated annual reconfiguration auction, of the product of the Capacity Supply Obligations acquired through the annual reconfiguration auction in each zone (adjusted for any obligations procured in the annual reconfiguration auction that are subsequently terminated pursuant to Section III.13.3.4A) and the zonal annual reconfiguration auction clearing price, minus the sum, for all Capacity Zones, of the product of the amount of any Capacity Supply Obligation shed through the annual reconfiguration auction in each zone and the applicable annual reconfiguration auction clearing price.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

**III.13.7.5.1.1.3. Monthly Reconfiguration Auction Charge.**

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price, minus the sum of, for all Capacity Zones, any Capacity Supply Obligations shed through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

**III.13.7.5.1.1.4. HQICC Capacity Charge.**

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

**III.13.7.5.1.1.5. Self-Supply Adjustment.**

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied FCA Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

**III.13.7.5.1.1.6. Intermittent Power Resource Capacity Adjustment.**

The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where

Intermittent Power Resource Seasonal Variance is the difference between the FCA payments for Intermittent Power Resource in the Obligation Month and the base FCA payments for Intermittent Power Resources.

FCA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to or shed by Intermittent Power Resources in the Forward Capacity Auction process for the Obligation Month pursuant to Section III.13.2.7.6 or Section III.13.2.8.1.1 (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base FCA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the FCA Qualified Capacity procured from or shed by Intermittent Power Resources in the Forward Capacity Auction process (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Zonal Capacity Obligation in all Capacity Zones.

**III.13.7.5.1.1.7. Multi-Year Rate Election Adjustment.**

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity

Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

**III.13.7.5.1.1.8 CTR Transmission Upgrade Charge.**

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.13.7.5.4.4 (f), multiplied by

the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

**III.13.7.5.1.1.9 CTR Pool-Planned Unit Charge.**

The CTR Pool-Planned Unit charge is: (a) the total Capacity Load Obligation in all Capacity Zones less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5.

Where

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.13.7.5.4.5 (b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

**III.13.7.5.1.1.10. Failure to Cover Charge Adjustment.**

The failure to cover charge adjustment, for each Capacity Zone, is (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Failure to Cover Charges divided by Total Capacity Load Obligation.

Where:

Zonal Failure to Cover Charges are the product of: (1) the sum, for all Capacity Zones, of the failure to cover charges calculated pursuant to Section III.13.3.4(b), and; (2) the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price as determined pursuant to Section III.13.3.4.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

**III.13.7.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.**

The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals for Capacity Commitment Periods beginning prior to June 1, 2022 and excluding any additional obligations awarded to Intermittent Power Resources pursuant to Section III.13.2.7.6 that exceed the FCA Qualified Capacity procured in the Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022) plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022) to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022).

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; when all load of a Distributed Energy Resource Aggregation participating as a Storage DARD is load associated with the receipt of electricity from the grid for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each day of the month and each Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above

and (ii) the ratio of the sum of the load serving entity's daily Coincident Peak Contributions, to the sum of all load serving entities' daily Coincident Peak Contributions in that Capacity Zone.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each day of the month and each Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource, Demand Response Resource, or a Demand Response Distributed Energy Resource Aggregation.

**III.13.7.5.2.1. Charges Associated with Dispatchable Asset Related Demands.**
Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

**III.13.7.5.3. Excess Revenues**.
(a) For Capacity Commitment Periods beginning prior to June 1, 2022, revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.5.3.

(b) Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section III.13.3.4A shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

**III.13.7.5.4. Capacity Transfer Rights.**

**III.13.7.5.4.1. Definition and Payments to Holders of Capacity Transfer Rights.**

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

Capacity Transfer Rights are calculated for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone's Net Regional Clearing Price and absolute value of each Capacity Zone's Capacity Load Obligations, as calculated in Section III.13.7.5.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources.

**III.13.7.5.4.2. Allocation of Capacity Transfer Rights.**

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.5.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface**. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface**. Except as provided in Section III.13.7.5.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

**III.13.7.5.4.3. Allocations of CTRs Resulting From Revised Capacity Zones.**

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.5.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

**III.13.7.5.4.4. Specifically Allocated CTRs Associated with Transmission Upgrades.**

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(e) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine export interface for as long as Casco Bay continues to pay to support the transmission upgrades.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. This value will be divided by the number of days in the month to derive a daily settlement value.

**III.13.7.5.4.5. Specifically Allocated CTRs for Pool-Planned Units.**

(a) In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive for each Capacity Commitment Period an allocation of CTRs for each such unit that is the product of: (i) the MW quantity of capacity that the unit cleared in the Forward Capacity Auction associated with the Capacity Commitment Period; and (ii) the municipal utility's ownership entitlements in such unit. The CTRs

allocated pursuant to this Section may be designated as self-supply quantities as described in Section III.13.1.6. Municipal utility ownership entitlements are set as shown in the table below and are not transferrable.

| | Millstone 3 | Seabrook | Stonybrook GT 1A | Stonybrook GT 1B | Stonybrook GT 1C | Stonybrook 2A | Stonybrook 2B | Wyman 4 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | |
| Danvers | 0.2627% | 1.1124% | 8.4569% | 8.4569% | 8.4569% | 11.5551% | 11.5551% | 0.0000% | | |
| Georgetown | 0.0208% | 0.0956% | 0.7356% | 0.7356% | 0.7356% | 1.0144% | 1.0144% | 0.0000% | | |
| Ipswich | 0.0608% | 0.1066% | 0.2934% | 0.2934% | 0.2934% | 0.0000% | 0.0000% | 0.0000% | | |
| Marblehead | 0.1544% | 0.1351% | 2.6840% | 2.6840% | 2.6840% | 1.5980% | 1.5980% | 0.2793% | | |
| Middleton | 0.0440% | 0.3282% | 0.8776% | 0.8776% | 0.8776% | 1.8916% | 1.8916% | 0.1012% | | |
| Peabody | 0.2969% | 1.1300% | 13.0520% | 13.0520% | 13.0520% | 0.0000% | 0.0000% | 0.0000% | | |
| Reading | 0.4041% | 0.6351% | 14.4530% | 14.4530% | 14.4530% | 19.5163% | 19.5163% | 0.0000% | | |
| Wakefield | 0.2055% | 0.3870% | 3.9929% | 3.9929% | 3.9929% | 6.3791% | 6.3791% | 0.4398% | | |
| Ashburnham | 0.0307% | 0.0652% | 0.6922% | 0.6922% | 0.6922% | 0.9285% | 0.9285% | 0.0000% | | |
| Boylston | 0.0264% | 0.0849% | 0.5933% | 0.5933% | 0.5933% | 0.9120% | 0.9120% | 0.0522% | | |
| Braintree | 0.0000% | 0.6134% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | |
| Groton | 0.0254% | 0.1288% | 0.8034% | 0.8034% | 0.8034% | 1.0832% | 1.0832% | 0.0000% | | |
| Hingham | 0.1007% | 0.4740% | 3.9815% | 3.9815% | 3.9815% | 5.3307% | 5.3307% | 0.0000% | | |
| Holden | 0.0726% | 0.3971% | 2.2670% | 2.2670% | 2.2670% | 3.1984% | 3.1984% | 0.0000% | | |
| Holyoke | 0.3194% | 0.3096% | 0.0000% | 0.0000% | 0.0000% | 2.8342% | 2.8342% | 0.6882% | | |
| Hudson | 0.1056% | 1.6745% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.3395% | | |
| Hull | 0.0380% | 0.1650% | 1.4848% | 1.4848% | 1.4848% | 2.1793% | 2.1793% | 0.1262% | | |
| Littleton | 0.0536% | 0.1093% | 1.5115% | 1.5115% | 1.5115% | 3.0607% | 3.0607% | 0.1666% | | |
| Mansfield | 0.1581% | 0.7902% | 5.0951% | 5.0951% | 5.0951% | 7.2217% | 7.2217% | 0.0000% | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Middleborough | 0.1128% | 0.5034% | 2.0657% | 2.0657% | 2.0657% | 4.9518% | 4.9518% | 0.1667% | | |
| North Attleborough | 0.1744% | 0.3781% | 3.2277% | 3.2277% | 3.2277% | 5.9838% | 5.9838% | 0.1666% | | |
| Pascoag | 0.0000% | 0.1068% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | |
| Paxton | 0.0326% | 0.0808% | 0.6860% | 0.6860% | 0.6860% | 0.9979% | 0.9979% | 0.0000% | | |
| Shrewsbury | 0.2323% | 0.5756% | 3.9105% | 3.9105% | 3.9105% | 0.0000% | 0.0000% | 0.4168% | | |
| South Hadley | 0.5755% | 0.3412% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | |
| Sterling | 0.0294% | 0.2044% | 0.7336% | 0.7336% | 0.7336% | 1.1014% | 1.1014% | 0.0000% | | |
| Taunton | 0.0000% | 0.1003% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | |
| Templeton | 0.0700% | 0.1926% | 1.3941% | 1.3941% | 1.3941% | 2.3894% | 2.3894% | 0.0000% | | |
| Vermont Public Power Supply Authority | 0.0000% | 0.0000% | 2.2008% | 2.2008% | 2.2008% | 0.0000% | 0.0000% | 0.0330% | | |
| West Boylston | 0.0792% | 0.1814% | 1.2829% | 1.2829% | 1.2829% | 2.3041% | 2.3041% | 0.0000% | | |
| Westfield | 1.1131% | 0.3645% | 9.0452% | 9.0452% | 9.0452% | 13.5684% | 13.5684% | 0.7257% | | |

Allocation of CTRs as described in this Section shall expire on December 31, 2040. If a unit listed in the table above retires prior to December 31, 2040, however, allocation of CTRs for such unit shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) For any CTRs specifically allocated pursuant to this Section that are not designated self-supply quantities for the Capacity Commitment Period, the municipal utility entitlement holder shall receive a credit reflecting the value of such remaining CTRs. The value of each remaining CTR shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located; and (ii) the remaining MW quantity. This value will be divided by the number of days in the month to derive a daily settlement value.

**III.13.7.5.5. Forward Capacity Market Net Charge Amount.**

The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charges; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund (for Capacity Commitment Periods beginning prior to June 1, 2022); and (d) any applicable export charges.

## III.15. Annual Capacity Market.

(a) Annual Capacity Market Overview.

The ISO shall administer an annual market for capacity (Annual Capacity Market) in accordance with the provisions of this Section III.15. For each one-year period from June 1 through May 31, starting with the period June 1, 2028 to May 31, 2029, for which Capacity Supply Obligations are assumed and payments are made in the Annual Capacity Market ("Capacity Commitment Period"), the ISO shall conduct an Annual Capacity Auction in accordance with the provisions of Section III.15.4 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Annual Capacity Auction, a resource must have Qualified Capacity resulting from the Annual Capacity Auction qualification process in accordance with the provisions of Sections III.15.2 and III.15.3. Obligations associated with the Annual Capacity Market may be traded during ISO-administered Monthly Reconfiguration Auctions and monthly bilateral transactions, in accordance with Section III.15.5 and Section III.15.6, respectively. The obligations of resources with Capacity Supply Obligations resulting from the Annual Capacity Auction, Monthly Reconfiguration Auctions, and monthly bilateral transactions are set forth in Section III.15.7. Payments and charges resulting from participation in the Annual Capacity Market, Monthly Reconfiguration Auctions, and bilateral transactions, as well as Capacity Performance Payments, are set forth in Section III.15.8. The publication of auction-related information is set forth in Section III.15.9.

(b) Capacity Auction Calendar.

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2028, and for each Capacity Commitment Period thereafter, the ISO shall publish a calendar of dates and deadlines for the administration of the Capacity Market, with the dates and deadlines being consistent for each Annual Capacity Auction cycle. The Capacity Auction Calendar shall include specific dates and deadlines for all such Capacity Market dates and deadlines defined in this Section III.15 and related Tariff provisions. The following defines several milestone dates and deadlines.

(1) the Qualification Data Submission Deadline for the Annual Capacity Auction shall occur during the month of February;

(2) the Capacity Demonstration Deadline for the Annual Capacity Auction shall occur during the month of April; and

(3) the Annual Capacity Auction shall occur during the month of May.

(c) Modification of Capacity Auction Calendar.

The ISO may, on a prospective basis, reasonably revise any date or deadline in the Capacity Auction Calendar with written notice of such revision to each Governance Participant in the manner specified in Section 17.11(b) of the Participants Agreement prior to the occurrence of the date or deadline being revised. In the event a Market Participant fails to meet a deadline in the Capacity Auction Calendar for submission of information or data, the ISO shall extend such deadline for that Market Participant upon receipt of an order from the Commission granting the Market Participant's request for a waiver of such deadline for good cause shown. In no event shall a date or deadline be extended, prospectively by the ISO or retroactively by filing of a Market Participant, should doing so interfere with the ISO's effective administration of the Capacity Market.

(d) Effectiveness for the 2028-2029 Capacity Commitment Period and Thereafter.

The provisions of this Section III.15 are effective for the Capacity Commitment Period that runs from June 1, 2028 through May 31, 2029 and all Capacity Commitment Periods thereafter. Unless otherwise expressly stated, the provisions of this Section III.15 are not applicable to the Forward Capacity Market. Section III.13, addressing the administration of the Forward Capacity Market, shall continue to be effective for Capacity Commitment Periods through May 31, 2028. Unless otherwise expressly stated, the provisions of Section III.13 are not applicable to the Annual Capacity Market, Monthly Reconfiguration Auctions and monthly bilateral transactions addressed in this Section III.15 of Market Rule 1.

**III.15.A. Non-Commercial Capacity Transition Rules.**

All Capacity Resources that are on critical path schedule monitoring pursuant to Section III.13.3 as of June 1, 2028 are subject to the provisions of this Section III.15.A.

The ISO shall monitor the Non-Commercial Capacity resource's compliance with its critical path schedule from the time the ISO approves the request until the resource achieves FCM Commercial Operation, is terminated pursuant to Section III.15.A.2.1, or withdraws from critical path schedule monitoring pursuant to Section III.15.A.2.3.

**III.15.A.1. Non-Commercial Capacity Resource Critical Path Schedule Reports.**

For each resource that is being monitored for compliance with its critical path schedule, the Lead Market Participant for that resource must provide a written critical path schedule report to the ISO no later than five Business Days after the end of each calendar quarter. If the Lead Market Participant does not provide a written critical path schedule report to the ISO by the fifth Business Day after the end of the calendar quarter, then the ISO shall issue a notice thereof to the Lead Market Participant. If the Lead Market Participant fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.15.A.2.1. Each critical path schedule report shall include a complete updated version of the critical path schedule as described in Section III.15.A.1.1 through Section III.15.A.1.3.

**III.15.A.1.1. Updated Critical Path Schedule.**

The critical path schedule report must include a complete updated version of the critical path schedule as described in Section III.15.A.1, dated contemporaneously with the submission of the critical path schedule report. The updated critical path schedule must clearly indicate if the Lead Market Participant is proposing to change any of the milestones or dates from the previously submitted version of the critical path schedule, and must include an explanation of any such proposed changes. In the critical path schedule report, the Lead Market Participant must also explain in detail any proposed changes to the project design and the potential impact of such changes on the amount of capacity the resource will be able to provide.

**III.15.A.1.2. Documentation of Milestones Achieved.**

(a) For all new resources (except for Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW,

which are discussed in Section III.15.A.1.2(b)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Lead Market Participant must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Major Permits**. For each major permit described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the permit was applied for and obtained as described in the critical path schedule. For permit applications, this documentation could include a dated copy of the permit application or cover letter requesting the permit. For approved permits, this documentation could include a dated copy of the approved permit or letter granting the permit from the permitting authority.

(ii) **Project Financing Closing**. The Lead Market Participant shall provide documentation showing that the sources of financing identified in the critical path schedule have committed to provide the amount of financing described in the critical path schedule. This documentation could include copies of commitment letters from the sources of financing.

(iii) **Major Equipment Orders**. For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the equipment was ordered as described in the critical path schedule. This documentation should include a copy of a dated confirmation of the order from the manufacturer or supplier. This documentation should confirm scheduled delivery dates consistent with milestone Section III.15.A.1.2(a)(v).

(iv) **Substantial Site Construction.** The Lead Market Participant shall provide documentation showing that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs.

(v) **Major Equipment Delivery**. For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the equipment was delivered to the project site and received as preliminarily acceptable as described in the critical path schedule. This documentation should include a copy of a dated confirmation of delivery to the project site.

(vi) **Major Equipment Testing.** For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the component was tested, including major systems testing as appropriate for the specific technology as described in the critical path schedule, and that the test results demonstrate the equipment's suitability to allow, in conjunction with other major components, subsequent operation of the project in accordance with the amount of capacity subject to critical path schedule monitoring in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning**. The Lead Market Participant shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity subject to critical path schedule monitoring. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Lead Market Participant is not required to provide documentation of Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) to the ISO as part of the ISO's critical path schedule monitoring. The ISO shall confirm that the resource has achieved Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) as described in the critical path schedule through the resource's compliance with the other relevant requirements of the Transmission, Markets and Services Tariff and the ISO New England System Rules.

(ix) **Transmission Upgrades**. The Lead Market Participant shall provide documentation showing that all interconnection facilities and upgrades identified for the project associated with the resource in a Transitional Cluster Study, Cluster Study, or Cluster Restudy (conducted pursuant to Section 7.5 of Schedule 22, Section 7.5 of Schedule 23, or Section 7.5 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff), or interconnection request or agreement under applicable state tariff, rules or procedures, have been completed.

(b) For Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Lead Market

Participant must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion**. The Lead Market Participant shall provide documentation showing the resource will be capable of providing its total offered demand reduction value as described in the New Demand Capacity Resource Qualification Package by the proposed Commercial Operation Date reported in the critical path schedule report.

(ii) **Additional Requirements**. For each customer and each prospective customer the Lead Market Participant shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Asset has been registered with the ISO, then the Lead Market Participant shall also provide the Asset identification number.

**III.15.A.1.3. Additional Relevant Information.**

The Lead Market Participant must include in the critical path schedule report any other information regarding the status or progress of the project or any of the project milestones that might be relevant to the ISO's evaluation of the feasibility of the project being built in accordance with the critical path schedule.

**III.15.A.2. Failure to Meet Critical Path Schedule.**

If the ISO determines that any critical path schedule milestone date has been missed, or if the Lead Market Participant proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.15.A.1), then the ISO shall consult with the Lead Market Participant to determine the impact of the missed milestone or proposed revision, and shall determine a revised date for the milestone and for any other milestones affected by the change. If a milestone date is revised for any reason, the ISO may require the Lead Market Participant to submit a written report to the ISO on the fifth Business Day of each month until the revised milestone is achieved detailing the progress toward meeting the revised milestone. If the Lead Market Participant does not provide a written critical path schedule report to the ISO on the fifth Business Day of a month, then the ISO shall issue a notice thereof to the Lead Market Participant. If the Lead Market Participant fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.15.A.2.1. Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.15.A.1.

**III.15.A.2.1. Termination of Critical Path Schedule Monitoring.**

If a Lead Market Participant fails to comply with the requirements of Sections III.15.A.1 or III.15.A.2, or if, as a result of milestone date revisions, the date by which a resource will have achieved all its critical path schedule milestones is more than two years after the beginning of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation, then the ISO, after consultation with the Lead Market Participant, shall have the right, through a filing with the Commission, to terminate the resource's status on critical path schedule monitoring, provided that, where a Lead Market Participant voluntarily withdraws its resource from critical path schedule monitoring in accordance with Section III.15.A.2.3 no filing with the Commission shall be necessary. Upon Commission ruling, the Lead Market Participant shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation. If in these circumstances, however, the ISO does not take steps to terminate the resource and instead permits the Lead Market Participant to continue on critical path schedule monitoring, such continuation shall be subject to the ISO's right to revoke that permission and to file with the Commission to terminate the resource, and subject to continued reporting by the Lead Market Participant in accordance with Section III.15.A.1.

**III.15.A.2.2. Termination of Interconnection Agreement.**

If the ISO terminates, or files with the Commission to terminate, a resource's ability to remain on critical path schedule monitoring, the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. The ISO shall also reduce the resource's assigned capacity interconnection service (or equivalent for resources not subject to the ISO Interconnection Procedures).

**III.15.A.2.3. Withdrawal from Critical Path Schedule Monitoring**.

A Lead Market Participant may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO.

**III.15.A.3. Financial Assurance.**

The financial assurance requirements for Designated FCM Participants offering Non-Commercial Capacity into the Forward Capacity Auction, as described in Section VII.B.2.b the ISO New England Financial Assurance Policy, shall continue to apply to all Capacity Resources that are subject to the provisions of this Section III.15.A.

Once a resource with Non-Commercial Capacity achieves commercial operation, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as a resource that has achieved Capacity Market Commercial Operation, as governed by the ISO New England Financial Assurance Policy.

If a Capacity Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited. Any financial assurance that is forfeited pursuant to Section III.15.A shall be used to reduce charges incurred by load in the relevant Capacity Zone.

**III.15.A.4. Demonstrating FCM Commercial Operation**

All Capacity Resources subject to the provisions of this Section III.15.A shall achieve commercial operation, for purposes of ending critical path schedule monitoring, in accordance with the FCM Commercial Operation requirements specified in Section III.13.3.8.

**III.15.A.5. Settlement of Qualification Process Cost Reimbursement Deposit.**

Upon the date on which the entire resource is no longer on critical path schedule monitoring, the ISO shall provide the Lead Market Participant with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff. All Capacity Resources that are subject to the provisions of this Section III.15.A shall be subject to the Forward Capacity Market payment and refund requirements as set forth in Section III.13.1.9.3.2 of the Tariff.

**III.15.1. Auction Demand Curves and Other Auction Inputs.**

**III.15.1.1. Annual Capacity Auction Demand Curves**.

The total amount of capacity cleared in the Annual Capacity Auction pursuant to Section III.15.4 shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the Capacity Zones modeled for the Annual Capacity Auction.

**III.15.1.1.1. System-Wide Capacity Demand Curve.**

The System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.15.1.1.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Capacity Auction Offer Price Cap.

**III.15.1.1.2. Import-Constrained Capacity Zone Demand Curves.**

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.15.1.1.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Capacity Auction Offer Price Cap.

**III.15.1.1.3. Export-Constrained Capacity Zone Demand Curves.**

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.15.1.1.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

**III.15.1.1.4. Capacity Demand Curve Scaling Factor.**

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

**III.15.1.2. Capacity Auction Offer Price Cap and the Cost of New Entry.**

**III.15.1.2.1. Calculation of Capacity Auction Offer Price Cap, CONE, and Net CONE.**

(a) The Capacity Auction Offer Price Cap shall be the greater of (i) 1.6 multiplied by Net CONE; and (ii) CONE. References in this Section III.15 and Sections III.A.21 and III.A.24 to the Capacity Auction Offer Price Cap shall mean the Capacity Auction Offer Price Cap for the Annual Capacity Auction associated with the relevant Capacity Commitment Period.

(b) To determine the CONE and Net CONE for the Annual Capacity Auctions associated with the Capacity Commitment Period beginning on June 1, 2028 and the Capacity Commitment Period beginning on June 1, 2029, the ISO shall make interim-year adjustments as described in Section III.15.1.2.2 to the following CONE and Net CONE calculated for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025:

(i) CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 was $12.400/kW-month.

(ii) Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 was $7.468/kW-month.

(c) The ISO shall recalculate CONE and Net CONE for the Annual Capacity Auction for the Capacity Commitment Period beginning on June 1, 2030. Thereafter, CONE and Net CONE shall be recalculated no less often than once every four years. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders, and the new values will be filed with the Commission prior to the Annual Capacity Auction in which the new value is to apply.

**III.15.1.2.2. Interim-Year Adjustments to CONE and Net CONE.**

(a) For years in which no full recalculation is performed pursuant to Section III.15.1.2.1, CONE and Net CONE shall be adjusted for each Annual Capacity Auction with the following updates to the capital

budgeting model used to calculate the CONE and Net CONE values set forth above in this Section III.15.1.2:

(1) Each line item associated with capital costs that is included in the capital budgeting model shall be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114).

(2) For each line item in (1) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the CONE and Net CONE values set forth in Section III.15.1.2.1. The value of each line item associated with capital costs in the capital budgeting model will be adjusted by the relevant multiplier.

(3) The energy and ancillary services offset values in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE, for each month of the Capacity Commitment Period to which the updated value will apply.

(4) The annual adjustment to CONE and Net CONE for the Annual Capacity Auction for the Capacity Commitment Period beginning June 1, 2028, shall use a cost of debt of 6.85% and a cost of equity of 13.80%. These values shall also be used for the Annual Capacity Auction for the Capacity Commitment Period beginning on June 1, 2029.

(5) If any of the values required for the calculations described in this Section III.15.1.2.2 are unavailable, then comparable values, prices or sources shall be used.

(b) The CONE and Net CONE values adjusted pursuant to this Section III.15.1.2.2 will be published on the ISO's website.

**III.15.2. Capacity Resource Qualification.**

Each resource, or portion thereof, must qualify as a Generating Capacity Resource, an Import Capacity Resource, a Demand Capacity Resource, or a Distributed Energy Capacity Resource. Each resource must be at least 100 kW in size to participate in an Annual Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of Section III.13 became effective. The summer period of a Capacity Resource's Seasonal Qualified Capacity Values shall be the months of June through September and the winter period shall be the months of October through May, except in the case of Demand Capacity Resources, where the summer period shall be the months of April through November and the winter period shall be the months of December through March.

This Section III.15.2 details the requirements of the qualification process for the Annual Capacity Auction, as well as certain requirements related to Monthly Reconfiguration Auctions and Capacity Supply Obligation Bilateral transactions. Data submission and demonstration requirements for resources that have never previously counted as capacity and seek to qualify to participate in an Annual Capacity Auction, are set forth in Section III.15.2.1. Data submission and demonstration requirements for resources that have never previously counted as capacity and seek to qualify to participate in a Monthly Reconfiguration Auction are set forth in Section III.15.2.2. Qualification requirements with respect to interconnection service are addressed in Section III.15.2.3. Qualification requirements with respect to resources that have previously counted as capacity and have materially changed are addressed in Section III.15.2.4. Following the Annual Capacity Auction's Qualification Data Submission Deadline, the ISO calculates and provides to Lead Market Participants Advisory Qualified Capacity Values for each Capacity Resource, per Section III.15.2.5. Lead Market Participants then have until the Capacity Demonstration Deadline to demonstrate that their Capacity Resources have achieved Commercial Operation, per Section III.15.2.6. Thereafter, the ISO calculates Seasonal Qualified Capacity Values for each Capacity Resource, per Section III.15.2.7, which values are subject to the challenge process addressed therein. Lead Market Participants are then permitted to submit Composite Offers in accordance with Section III.15.2.8, and load serving entities are permitted to submit self-supply designations in accordance with III.15.2.9. Final Qualified Capacity values for each Capacity Resource are calculated by the ISO one Business Day prior to the opening of the Annual Capacity Auction Offer Window in accordance with Section III.15.2.10. The publication of offer information during the qualification process and after the Annual Capacity Auction is addressed in Section III.15.2.11.

Resources seeking to qualify for an Annual Capacity Auction may be subject to buyer-side market power review and mitigation pursuant to Section III.A.21 and must abide by the applicable submission

requirements and timelines set forth therein prior to seeking to qualify for an Annual Capacity Auction. To the extent not already established for the purposes of the submission requirements of Section III.A.21.1.5, all capacity suppliers seeking to qualify for an Annual Capacity Auction must be Market Participants prior to the Qualification Data Submission Deadline. The Lead Market Participant for a resource participating in an Annual Capacity Auction may not change during the period beginning 15 Business Days prior to the opening of the Annual Capacity Auction Offer Window and ending with the posting of the results of the Annual Capacity Auction.

**III.15.2.1. Qualification Data Submission Requirements.**

**III.15.2.1.1. Qualification Data Submission Package.**

(a) For a resource that has not previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction to qualify as a Capacity Resource for participation in an Annual Capacity Auction, a Lead Market Participant must submit the following information to the ISO by the Qualification Data Submission Deadline, as applicable:

(i) the resource name;

(ii) the Lead Market Participant's contact information;

(iii) the date by which the resource is expected to complete its capacity demonstration pursuant to III.15.2.6(c) or to update its as-built data pursuant to III.15.2.6(d);

(iv) the resource address or location, and if available, asset identification number;

(v) whether the resource has ever previously had a Capacity Supply Obligation;

(vi) the location of the resource's interconnection;

(vii) the estimated Seasonal Qualified Capacity Values of the resource, as well as an estimate of any incremental Seasonal Qualified Capacity Values (in MW) (for Generating Capacity Resources and Import Capacity Resources);

(viii) the estimated total summer and winter demand reduction value (for Demand Capacity Resources and Distributed Energy Capacity Resources) or net injection capability values per facility (for Distributed Energy Capacity Resources);

(ix) a description of the resource, including (for Generating Capacity Resources and Import Capacity Resources) a general description of the resource's equipment configuration and a description of the resource technology type, and (for Demand Capacity Resources) a description of the resource's Demand Capacity Resource type and measure type, and (for Distributed Energy Capacity Resources) a description of the project and its configuration, including the types of generation and demand response composing the project, and (for

Generating Capacity Resources and Distributed Energy Capacity Resources comprising generation) a one-line diagram of the resource's configuration;

(x) for resources supported by an Internal Elective Transmission Upgrade, all unique project identifiers associated with the Internal Elective Transmission Upgrade;

(xi) for Generating Capacity Resources with a contract to export capacity from the New England Control Area during the Capacity Commitment Period, the interface over which the capacity will be exported and the contract associated with the export capacity;

(xii) Additional requirements for Import Capacity Resources, the interface over which the capacity will be imported and one of the following submissions documenting the source of the imported capacity, as further detailed in Section III.15.2.1.1.1: (i) documentation of a contract entered into before the Qualification Data Submission Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for one or more years encompassing the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iii) documentation for system-backed import capacity that the Import Capacity Resource will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load.

(xiii) Additional requirements for Demand Capacity Resources, as further detailed in Section III.15.2.1.1.2: resource technical and credit/financial contacts; Measurement and Verification Plan (for On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources); Load Zone and Dispatch Zone (for Active Demand Capacity Resources);

(xiv) Additional requirements for Distributed Energy Capacity Resources, as further detailed in Section III.15.2.1.1.3: expected nameplate capacity by technology type per facility; installation date of facilities that are part of the project and already constructed, installed, or in commercial operation; indication of whether the project elects Intermittent Power Resource treatment; resource technical and credit/financial contacts; Load Zone, Dispatch Zone and DRR Aggregation Zone;

(xv) Additional requirements for resources with capacity impacted by ambient air conditions between 90 degrees and 100 degrees, as further detailed in Section III.15.2.1.5; and

(xvi) Additional requirements for resources seeking ISO-estimated Seasonal Qualified Capacity Values, as further detailed in III.15.2.6(d): the Qualification Data Submission Package shall satisfy the technical data requirements associated with such resources and be supplemented with the as-built status of the resource on the date of the relevant Capacity Demonstration Deadline.

(b) By submitting the required qualification information, the Lead Market Participant certifies that a Capacity Offer from the resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 of Section II of the Tariff.

(c) The ISO may waive the submission of any information not required for evaluation of the resource.

**III.15.2.1.1.1. Additional Import Capacity Resource Requirements.**

Import Capacity Resources must be backed by one or more External Resources or by an external Control Area for the duration of the relevant Capacity Commitment Period. An external demand resource may not be an Import Capacity Resource. External nodes shall be established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff. For the purposes of the qualification process, all Import Capacity Resources shall be treated as if they had never previously participated as capacity and must submit the materials described pursuant to this Section III.15.2.1.1 for each Capacity Commitment Period for which the Import Capacity Resource seeks to qualify capacity. Import Capacity Resources backed by an External Control Area that does not have a Coordination Agreement with the ISO shall be ineligible to participate in the Annual Capacity Market. No single Import Capacity Resource may qualify capacity in excess of the external interface limits as described in Section III.12.10.

An Elective Transmission Upgrade with Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall have its external node modeled in the Annual Capacity Auction after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Annual Capacity Auction qualification requirements of this Section III.15.2.1 and demonstration requirements of III.15.2.6. The Qualified Capacity of all Import Capacity Resources associated with an Elective Transmission Upgrade shall not exceed the Elective Transmission Upgrade's Capacity Network Import Capability.

Capacity Offers for Import Capacity Resources shall be subject to rationing except for Capacity Offers priced above the Capacity Offer Price Threshold for Import Capacity resources associated with an Elective Transmission Upgrade, which must obtain a Capacity Supply Obligation or not in whole unless the Capacity Offer indicated that it may be rationed as described in III.15.4.1.

**III.15.2.1.1.1.1. Imports Backed by External Resources.**

If the Import Capacity Resource will be backed by one or more External Resources, the Lead Market Participant shall submit a description of how the Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify. The description must indicate specifically which External Resources will back the Import Capacity Resource during the Capacity Commitment Period and contain the relevant historical performance data for each resource. If those External Resources are not owned or controlled directly by the Lead Market Participant, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

**III.15.2.1.1.1.2. Imports Backed by an External Control Area.**

If the Import Capacity Resource will be backed by an external Control Area, the Lead Market Participant shall submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the Import Capacity Resource.

**III.15.2.1.1.1.3. Imports Crossing Intervening Control Areas.**

Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) for imports crossing a single intervening Control Area, the Lead Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the Qualification Data Submission Deadline, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing; (2) for imports crossing more than one intervening Control Area, in addition to the requirements above, the Lead Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals,

by the Qualification Data Submission Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load; and (3) the Lead Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

**III.15.2.1.1.2. Additional Demand Capacity Resource Requirements.**

A Demand Capacity Resource may be an Active Demand Capacity Resource, On-Peak Demand Capacity Resource, or Seasonal Peak Demand Capacity Resource, and may include an end-use customer facility with a Net Supply Capability of 5 MW or more only if the facility's Net Supply Capability does not exceed its Maximum Facility Load. Demand Capacity Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Capacity Resource. Demand Capacity Resources are not permitted to submit a Capacity Offer to import into or export out of the New England Control Area.

For a resource, or portion thereof, that never previously obtained a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction to qualify as an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource for the Capacity Commitment Period beginning June 1, 2028, the measure or measures contained in the resource must not have been in-service prior to June 1, 2024. For a resource, or portion thereof, that never previously obtained a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction to qualify as an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource in the Annual Capacity Auction or Monthly Reconfiguration Auction, as relevant, for or during the Capacity Commitment Period beginning June 1, 2029, and all Capacity Commitment Periods thereafter, the measure or measures contained in the resource must have been placed in-service or previously qualified as capacity no more than six months before the prior Annual Capacity Auction's Capacity Demonstration Deadline.

**III.15.2.1.1.2.1. Measurement and Verification of Demand Capacity Resources.**

(a) To demonstrate the demand reduction value of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, the Lead Market Participant of such a resource participating in the Annual Capacity Auction, Capacity Supply Obligation Bilaterals, or Monthly Reconfiguration Auctions shall submit to the ISO Measurement and Verification Documents in accordance with this Section III.15.2.1.1.2.1 and the ISO New England Manuals. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.15.2.1.1.2.1 and the ISO New England Manuals.

(b) Measurement and Verification Documents must demonstrate both availability and performance of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource in reducing demand coincident with Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours such that the reported monthly demand reduction value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manuals and ISO New England Operating Procedures. The Measurement and Verification Documents shall: (1) serve as the basis for the claimed demand reduction value of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource; (2) document the measurement and verification performed to verify the achieved demand reduction value of the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource; and (3) contain a projection of the On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's demand reduction value for each month of the Capacity Commitment Period and, for those Demand Capacity Resources composed of energy efficiency measures, over the expected Measure Lives. An On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours. If an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource includes Distributed Generation, the Measurement and Verification Documents must describe the individual metering or metering protocol used to monitor and verify the output of the Distributed Generation, consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals.

(c) The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Annual Capacity Auction qualification process, as described in this Section III.15.2.1.1.2.1, and monthly Measurement and Verification data submitted during the Capacity Commitment Period. The monthly Measurement and Verification data shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan.

Such monthly Measurement and Verification data shall document the Lead Market Participant's total demand reduction value from both eligible pre-existing measures and new measures, and the Lead Market Participant's total demand reduction value from both eligible pre-existing measures and new measures, for all measures in operation as of the end of the previous month. The monthly Measurement and Verification data shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Lead Market Participants. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

(d) Lead Market Participants for On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources shall submit no less frequently than once per year, a statement certifying that the Demand Capacity Resource for which the Lead Market Participant is requesting compensation continues to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than ten Business Days before the Qualification Data Submission Deadline.

(e) For On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources comprising customer facilities with greater than or equal to 10 kW of demand reduction value per facility, Lead Market Participants shall maintain records of retail customers served, including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly demand reduction values. For On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources targeting customer facilities with under 10 kW of demand reduction value per facility, the Lead Market Participant shall maintain records as described above for customer facilities with greater than or equal to 10 kW of demand reduction value per facility, or shall maintain records of aggregated demand reduction values and measures installed by Load Zone and meter domain. Lead Market Participants shall maintain such records until the end of the Measure Life, or until the Demand Capacity Resource is retired or deactivated from the Annual Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

(f) The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Annual Capacity Auction qualification

process as described in Section III.15.2 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Lead Market Participant to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

**III.15.2.1.1.3. Additional Distributed Energy Capacity Resource Requirements.**

(a) Distributed Energy Capacity Resources. A facility connected at a point of interconnection that is 5 MW or greater cannot be a part of a Distributed Energy Capacity Resource. A Distributed Energy Capacity Resource comprises one or more Distributed Energy Resource Aggregations located in a single Capacity Zone and a single DRR Aggregation Zone, except that (a) a Settlement Only Distributed Energy Resource Aggregation may not participate in a Distributed Energy Capacity Resource with any other type of Distributed Energy Resource Aggregation, and (b) an end-use customer facility participating as part of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource with measures other than Energy Efficiency may not participate in a Distributed Energy Capacity Resource. Distributed Energy Capacity Resources are not permitted to submit a Capacity Offer to import into or export out of the New England Control Area. For purposes of this Section III.15.2.1.1.3: (i) if a facility is expected to interconnect at a point of interconnection, its net injection capability is the generation capability of the installed generation technology at the point of interconnection; (ii) if a facility is expected to interconnect at a Retail Delivery Point and does not plan to participate in the aggregation as a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation, the net injection capability is the lesser of the generation less the load profile measured at the location of the end-use customer meter or the amount the facility is contractually able to inject.

(b) Demand Response Resource in Distributed Energy Capacity Resources. If the Distributed Energy Capacity Resource includes Demand Response Resources, the completed Qualification Data Submission Package shall include the following additional information: the estimated summer and winter demand reduction values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses); the estimated total summer and winter demand reduction value of the Demand Response Resource (which must be consistent with the baseline calculation methodology in Section

III.8.2); and supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated demand reduction values.

(c) Net Injection of 5 MW or Greater. If the Distributed Energy Capacity Resource contains a Distributed Energy Resource Aggregation with a facility with net injection of 5 MW or greater at a Retail Delivery Point, then the completed Qualification Data Submission Package for such a resource shall include the following additional information: the Pnode and service address at which the end-use facility is located; nameplate MW and net injection capability; non-coincident peak load (MW) of the facility without generation; technology type; and the Market Participant's portion of generation requested to be included as Qualified Capacity.

(d) Net Injection Greater Than or Equal to 1 MW and less than 5 MW. If the Distributed Energy Capacity Resource contains a Distributed Energy Resource Aggregation with a facility that has net injection capability at the point of interconnection of 1 MW or greater and less than 5 MW, then the completed Qualification Data Submission Package for such a facility shall include the following additional information: distribution bus; technology type; nameplate MW; one-line diagram of the plant and station facilities, including any known transmission facilities; if the facility is intermittent, the requested contribution of Qualified Capacity and supporting site-specific data; if an interconnection agreement is required under state requirements, the date when the interconnection request was submitted and the status of that interconnection request.

**III.15.2.1.2. Market Power Review.**

Lead Market Participants seeking to qualify a Capacity Resource that has not previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or that is otherwise treated as if it had never done so pursuant to this Section III.15.2, must comply with the market power review provisions of Section III.A.21 by the Annual Capacity Auction Qualification Data Submission Deadline.

**III.15.2.1.3. Capacity Commitment Period Election.**

For the Annual Capacity Auctions for the 2028-2029, 2029-2030 and 2030-2031 Capacity Commitment Periods, a Lead Market Participant that has made the election in Section III.13.1.1.2.2.4 of the Forward Capacity Market rules with respect to a Capacity Resource must specify by the Qualification Data Submission Deadline whether it elects to continue to have the associated Capacity Supply Obligation and Capacity Clearing Price apply in Annual Capacity Auctions for the balance of the period permitted for

such Capacity Resource pursuant to Section III.13.1.1.2.2.4. Should a Lead Market Participant elect to terminate Section III.13.1.1.2.2.4 treatment for its Capacity Resource, it may not re-elect such treatment for any future Annual Capacity Auctions.

A Lead Market Participant that has made the election in Section III.13.1.1.2.2.4 of the Forward Capacity Market rules with respect to a Capacity Resource which has not achieved Capacity Market Commercial Operation as defined in Section III.15.2.6 of Market Rule 1 may not participate in the Annual Capacity Auction for the 2028-2029 Capacity Commitment Period and shall not have the previously elected Capacity Supply Obligation and Capacity Clearing Price apply for the 2028-2029 Capacity Commitment Period. Should such resource achieve Capacity Market Commercial Operation in time for participation in the Annual Capacity Auction for the 2029-2030 Capacity Commitment Period, or the Annual Capacity Auction for the 2030-2031 Capacity Commitment Period, it may elect to have the Capacity Supply Obligation and Capacity Clearing Price it received pursuant to Section III.13.1.1.2.2.4 apply for the balance of the period permitted for such Capacity Resource pursuant to Section III.13.1.1.2.2.4, and in no event after the Annual Capacity Auction for the 2030-2031 Capacity Commitment Period.

**III.15.2.1.4. Material Deficiency in Data Submission.**

In its review of a Lead Market Participant's data submission under this Section III.15.2.1, the ISO may consult with the Lead Market Participant, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO determines that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Lead Market Participant may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

In the event the ISO determines that a Lead Market Participant's data submission under Section III.15.2.1 is materially deficient, it shall notify the participant of such deficiencies at least ten Business Days prior to publication of the Advisory Seasonal Qualified Capacity Values, and the Lead Market Participant shall have five Business Days from the date of notification to cure the deficiencies. Should a Lead Market Participant fail to cure such deficiencies by the end of the cure period, it shall not be permitted to participate in the Annual Capacity Auction. In the event of such a rejection, the ISO shall provide the

Lead Market Participant with a written explanation of the reason for the rejection within ten Business Days of the close of the cure period.

**III.15.2.1.5. Additional Qualification Requirements for Ambient Air Condition Impacts.**

In the Qualification Data Submission Package, a Lead Market Participant may submit documentation indicating that a portion of its resource's capacity will not be physically available due to an ambient air condition. The size of such ambient air condition is calculated as the difference between the summer Qualified Capacity at 90 degrees and the rating of the resource at 100 degrees. The ISO shall verify during the qualification process the size of the ambient air condition.

**III.15.2.2. Monthly Reconfiguration Auction Qualification.**

For a resource that has not previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction to qualify as a Capacity Resource for the purpose of participation in a Monthly Reconfiguration Auction pursuant to Section III.15.5 or bilateral activities pursuant to Section III.15.6, prior to the Capacity Demonstration Deadline for the relevant month a Lead Market Participant must: (1) submit the Qualification Data Submission Package as described in Section III.15.2.1 (except for the information described at Section III.15.2.1.2) by the Capacity Demonstration Deadline for the relevant month, except that an Import Capacity Resource or a Resource seeking ISO-estimated Seasonal Qualified Capacity Values pursuant to Section III.15.2.6(d) must submit its Qualification Data Submission Package 30 calendar days prior to the Capacity Demonstration Deadline; and (2) complete a capacity demonstration pursuant to Section III.15.2.6.

**III.15.2.3. Deliverability Review.**

A Generating Capacity Resource, Active Demand Capacity Resource, Import Capacity Resource associated with an External Elective Transmission Upgrade, and Distributed Energy Capacity Resource must satisfy the deliverability review requirements described in this Section III.15.2.3 in order to qualify capacity for participation in an Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction above the deliverability value associated with the resource's qualification for any previous Forward Capacity Auction, Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction. None of the provisions of this Section III.15.2, supersedes, replaces, or satisfies any of the requirements of Schedules 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder.

**III.15.2.3.1. Deliverability Review for Capacity Resources Associated with Generating Facilities or External Elective Transmission Upgrades Subject to Schedule 22, 23, or 25 of Section II of the Tariff.**

A Generating Facility or External Elective Transmission Upgrade subject to Schedules 22, 23 or 25 of Section II of the Tariff must complete the applicable interconnection processes set forth therein and have been assigned, as applicable, either Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service, as necessary to support the delivery of the associated Capacity Resource's Qualified Capacity.

**III.15.2.3.2. Deliverability Review for Capacity Resources Associated with Resources Not Subject to Schedule 22, 23, or 25 of Section II of the Tariff.**

For a Generating Capacity Resource, Active Demand Capacity Resource, or Distributed Energy Capacity Resource not subject to Schedules 22, 23, or 25 of Section II of the Tariff, the ISO shall perform a deliverability review based on: (1) the information provided in the resource's Qualification Data Submission Package; and (2) the results of the ISO's most recent deliverability analysis, performed consistent with the criteria and conditions conducted as described in the ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that such a resource cannot deliver any of the requested incremental capacity, then the resource or incremental portion thereof shall not qualify for participation in the Capacity Market as reflected in the Seasonal Qualified Capacity Values issued pursuant to Section III.15.2.7; otherwise, the ISO shall determine that the requested Qualified Capacity of the Capacity Resource is deliverable, and the Capacity Resource shall be eligible to continue to proceed with the remainder of the processes described in this Section III.15.2.

**III.15.2.4. Resources Previously Counted as Capacity.**

Resources that have previously counted as capacity shall, for the purposes of Section III.15.2, be treated as if they had never previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction if: (1) there is a material change to the Capacity Resource as described in III.15.2.4.1, or (2) if a deactivated or retired resource seeks to re-enter the Capacity Market pursuant to III.15.2.4.2.

**III.15.2.4.1. Material Change to a Capacity Resource.**

(a) A Lead Market Participant that materially changes a Capacity Resource that has previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or plans to do so prior to the relevant Capacity Demonstration Deadline, may, by the relevant Qualification Data

Submission Deadline or monthly Capacity Demonstration Deadline, inform the ISO of that material change, update the information provided under Section III.15.2.1.1 to reflect the change to the Capacity Resource, and demonstrate its updated Commercial Capacity pursuant to Section III.15.2.6. The updated Qualified Capacity of the resource, accounting for the change, shall be calculated in accordance with Section III.15.3.1 for the subsequent Annual Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral. The Seasonal Qualified Capacity of a Capacity Resource that notifies the ISO of a material change but does not demonstrate pursuant to III.15.2.6 shall remain unmodified until demonstration of the material change occurs.

(b) For purposes of this Section III.15.2.4, a material change to a Capacity Resource is a change to the design or operating characteristics of the resource, including its interconnection facilities, that may have a significant effect on the reliability or operating characteristics associated with the Capacity Resource, and shall include, but not be limited to, changing the resource technology type, making a change to the Capacity Resource that increases or decreases the resource's Annual Qualified Capacity by greater than the lesser of 5 MW or 10 percent, or any change to the resource that requires a material modification to its interconnection agreement. No less than 30 calendar days prior to the Qualification Data Submission Deadline or Monthly Capacity Demonstration Deadline, as relevant, a Lead Market Participant may request, and the ISO shall within 20 calendar days provide, a determination regarding whether a change qualifies as a material change to a Capacity Resource pursuant to this Section III.15.2.4 and requires submission of the materials required pursuant to Section III.15.2.1.1.

**III.15.2.4.2. Treatment of Previously Deactivated or Retired Resources.**

In order to qualify for participation in the Capacity Market, a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) must: (1) have reached its deactivation date and reduced its Capacity Network Resource Capability pursuant to Section II.48.3; (2) if the resource was compensated for delaying deactivation through a Commission-approved cost-of-service agreement, have refunded to the ISO all costs subject to refund under the claw-back provision set forth in Section II.54.1; and (3) have satisfied the provisions of Section III.15.2, including submission of the Qualification Data Submission Package described in Section III.15.2.1 and completed the capacity interconnection service requirements described in Section III.15.2.3, as if the resource had never previously received a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction.

**III.15.2.5. Calculation of Advisory Qualified Capacity Values.**

Following the Qualification Data Submission Deadline, by a date in the month of February published on the Capacity Auction Calendar, the ISO shall calculate and provide to Lead Market Participants summer and winter Advisory Qualified Capacity Values for each resource that has met the data submission requirements in Section III.15.2.1. The Advisory Qualified Capacity Values of any resource that has not previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or is otherwise treated as if it had not done so, shall equal its demonstrated Commercial Capacity determined in accordance with Section III.15.2.6; except that in the event that a resource has not yet demonstrated a portion of its Commercial Capacity, its Advisory Qualified Capacity Values shall equal the sum of its Commercial Capacity and the estimated incremental Seasonal Qualified Capacity Values of the resource as submitted pursuant to Section III.15.2.1. For all other resources, the Advisory Qualified Capacity Values shall equal the Capacity Resource's summer and winter Qualified Capacity as calculated pursuant to Section III.15.3.

During the period beginning with the ISO's issuance of Advisory Qualified Capacity Values and ending with the conclusion of the Annual Capacity Auction, any change to a capacity resource or the information submitted in a Qualification Data Submission Package shall not impact the resource's Seasonal Qualified Capacity Values for that Annual Capacity Auction unless the change has already been accounted for in the submitted Qualification Data Submission Package, or is made pursuant to Section III.15.2.1.4 or Section III.15.2.7.

**III.15.2.6. Capacity Commercial Operation Demonstration Requirement.**

To participate in an Annual Capacity Auction, Monthly Reconfiguration Auctions, or a Capacity Supply Obligation Bilateral transaction, a Capacity Resource must first demonstrate that its capacity is commercially operational by meeting the demonstration requirements in this Section III.15.2.6 by the applicable Capacity Demonstration Deadline. A resource that meets the demonstration requirements of this Section III.15.2.6 shall be deemed to have achieved Capacity Market Commercial Operation.

(a) Demonstration must be completed (i) prior to a Capacity Resource's initial participation in the Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction, and (ii) when a Capacity Resource that has previously received a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction materially changes or reactivates pursuant to Section III.15.2.4.

(b) The Capacity Demonstration Deadline for each Annual Capacity Auction shall be during the month of April preceding the relevant Annual Capacity Auction, as published on the Capacity Auction

Calendar; for each Monthly Reconfiguration Auction and Capacity Supply Obligation Bilateral window, the Capacity Demonstration Deadline shall precede the relevant Obligation Month by approximately two weeks, as published on the Capacity Auction Calendar.

(c) To demonstrate commercial capacity, a resource must perform an audit by the relevant Capacity Demonstration Deadline, using the following audit requirements:

(i) For Generating Capacity Resources that are not Intermittent Power Resources, each Generator Asset must perform an Establish Claim Capability Audit pursuant to Section III.1.5.1.2, provide the data described in ISO New England Operating Procedure No. 23, and have its audit value become effective pursuant to Section III.1.5.1.2(d)(iv).

(ii) For Generating Capacity Resources that are Intermittent Power Resources, each Generator Asset must perform a Seasonal Claim Capability Audit pursuant to Section III.1.5.1.3, provide the data described in ISO New England Operating Procedure No. 23, and have its audit value become effective pursuant to Section III.1.5.1.3(i).

(iii) For Active Demand Capacity Resources, each Demand Response Asset must perform a Seasonal DR Audit pursuant to III.1.5.1.3.1, as specified by season in III.15.7.1.5.3(c), requested by the Lead Market Participant, and have its audit value become effective pursuant to Section III.1.5.1.3.1(m).

(iv) For Demand Capacity Resources that are not Active Demand Capacity Resources, each Demand Capacity Resource must perform a Passive DR Audit pursuant to III.15.7.1.5.4, as specified by season in III.15.7.1.5.3(c), at the request of the Lead Market Participant, and have its audit value become effective pursuant to Section III.15.7.1.5.4(f).

(v) For Distributed Energy Capacity Resources, each asset comprising the Distributed Energy Capacity Resource must meet the demonstration requirement in sub-sections (i) through (iii) above for its corresponding asset type.

(vi) For Import Capacity Resources, demonstration is achieved through provision of performance data in the resource's Qualification Data Submission Package in accordance with Section III.15.2.1, except that Import Capacity Resources associated with an external Elective

Transmission Upgrade must demonstrate the ability to transfer power between regions pursuant to Schedule 25, Article 6.

(d) For those resources identified in Sections III.15.2.6(c)(ii), III.15.2.6(c)(iv), and III.15.2.6(c)(v) providing asset-level meter-based performance data by the Capacity Demonstration Deadline that is, as determined by the Lead Market Participant, of insufficient duration to establish accurate Seasonal Qualified Capacity Values, or for a period inconsistent with the audit described in Section III.15.2.6(c), the Lead Market Participant may request that the ISO determine Seasonal Qualified Capacity Values based on the lesser of: (1) the Seasonal Qualified Capacity Values requested for qualification by the Lead Market Participant; or (2) the Seasonal Qualified Capacity Values estimated by the ISO. In no instance shall the Seasonal Qualified Capacity Values developed pursuant to this Section III.15.2.6(d) exceed a resource's seasonal Capacity Network Resource Interconnection Service, or its equivalent.

The ISO-estimated Seasonal Qualified Capacity Values shall be based on technical data requirements for recently commercial resources identified in the Qualification Data Submission Package. The Qualification Data Submission Package of resources seeking ISO-estimated Seasonal Qualified Capacity Values shall include a description of the as-built status of the resource at time of submission, including whether the resource is fully or partially operational. For those resources seeking ISO-estimated Seasonal Qualified Capacity Values, the Qualification Data Submission Package must be submitted to the ISO by the Lead Market Participant by the Qualification Data Submission Deadline for the Annual Capacity Auction, or 30 days prior to the relevant monthly Capacity Demonstration Deadline, with the submission updated at the time of the Capacity Demonstration Deadline to reflect the as-built status of the resource. Resources satisfying the provisions of this Section III.15.2.6(d) shall be deemed to have demonstrated Commercial Capacity.

Resources seeking ISO-estimated Seasonal Qualified Capacity Values that have completed the relevant audit described in III.15.2.6(c) for only one season may elect to use the ISO-estimated Seasonal Qualified Capacity Values for one or both seasons. The ISO-estimated Seasonal Qualified Capacity Values may constitute a resource's Seasonal Qualified Capacity Value for up to one year after issuance, but shall be valid for no longer than one year after a resource becomes fully operational. A Lead Market Participant may request replacement of ISO-estimated Seasonal Qualified Capacity Values once the relevant seasonal audit has been completed.

**III.15.2.7. Seasonal Qualified Capacity Values and Challenge Process.**

(a) Following the April Capacity Demonstration Deadline, for each Capacity Resource qualified to participate in an Annual Capacity Auction, the ISO shall notify the Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity, calculated in accordance with Section III.15.3, and the Load Zone in which the resource is located. This notification will be provided by the Seasonal Qualified Capacity Notification Date specified in the Capacity Auction Calendar.

(b) If the Lead Market Participant believes that the ISO has made a mathematical error in calculating the summer Qualified Capacity or winter Qualified Capacity for a Capacity Resource, then the Lead Market Participant must notify the ISO within five calendar days of the Seasonal Qualified Capacity Notification Date.

(c) If a Capacity Resource's summer Qualified Capacity has been subject to a significant decrease pursuant to Section III.15.3.6, the Lead Market Participant may submit a restoration plan in accordance with Section III.15.3.6(b) within five calendar days of the Seasonal Qualified Capacity Notification Date.

(d) The ISO shall notify the Lead Market Participant of the outcome of any challenge submitted under (b) above or of its determination regarding the sufficiency of a restoration plan submitted under (c) above, by the date specified in the Capacity Auction Calendar for such responses. In assessing the sufficiency of a restoration plan, the ISO shall determine whether the plan provides sufficient information to support the reasonable likelihood of the resource providing capacity consistent with its summer Qualified Capacity value by the start of the Capacity Commitment Period.

**III.15.2.8. Offers Composed of Separate Resources (Composite Offers).**

Separate resources seeking to participate together in an Annual Capacity Auction shall submit a Composite Offer Form no later than the Composite Offer Deadline, which shall be approximately two business days prior to the auction as specified in the Capacity Auction Calendar, with the exception that Distributed Energy Capacity Resources may not participate in composite offers. Composite offers may not be modified or withdrawn after the Composite Offer Deadline. Composite offers must meet the following conditions:

(a) In all months of the summer period of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources combined meet the amount of the offer in all

months of the winter period; and (ii) to combine for a month, that month must be a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of a composite offer must qualify in accordance with all of the provisions of Section III.15.2 applicable to that resource type. A composite offer participates in the Annual Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period.

(c) The summer Qualified Capacity of a composite offer shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.15.3.7 shall apply, even where one or more of the resources that are part of the offer composed of separate resources is an Intermittent Power Resource. If the winter capacity of the composite offer in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) Composite offers are subject to the locational restrictions specified in the following table:

| | | **Location of Summer Resource** | | | |
|---|---|---|---|---|---|
| | | Import-Constrained Capacity Zone | Rest-of-Pool Capacity Zone | Export-Constrained Capacity Zone | Nested Export-Constrained Capacity Zone |
| **Location of Winter Resource** | Import-Constrained Capacity Zone | Eligible (within same Capacity Zone) | Eligible | Eligible | Eligible |
| | Rest-of-Pool Capacity Zone | Ineligible | Eligible | Eligible | Eligible |
| | Export-Constrained Capacity Zone | Ineligible | Ineligible | Eligible (within same Capacity Zone) | Eligible (within same Capacity Zone where nested export-constrained Capacity Zone is located) |

| | | | | | |
|---|---|---|---|---|---|
| | Nested Export-Constrained Capacity Zone | Ineligible | Ineligible | Ineligible | Eligible (within same Capacity Zone) |

**III.15.2.9. Self-Supplied Capacity.**

Where a load serving entity elects to designate all or a portion of its Capacity Load Obligation as self-supplied, the load serving must make such designation to the ISO during the self-supply designation window, as published in the Capacity Auction Calendar on the ISO's website. The load serving entity's designation shall specify the MW amount and Lead Market Participant providing the self-supplied capacity. During the Annual Capacity Auction Offer Window, the Lead Market Participant supplying such capacity shall confirm the load serving entity's self-supply designation by specifying each Self-Supplied Capacity Resource and the MW amount of self-supplied capacity in its Capacity Offer. A Generating Capacity Resource or an Import Capacity Resource may be designated as a Self-Supplied Capacity Resource. A Distributed Energy Capacity Resource may only designate its net injection capability as a Self-Supplied Capacity Resource. All self-supplied capacity shall be subject to the eligibility and locational requirements in this Section III.15.2.9. If designated as a Self-Supplied Capacity Resource the resource will clear in the Annual Capacity Auction as described in Section III.15.4 and, with the exception of demand programs for Self-Supplied Capacity Resources, shall offset an equal amount of the load serving entity's Capacity Load Obligation in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Capacity Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.15.2. All designations as a Self-Supplied Capacity Resource in the Annual Capacity Auction qualification process are binding.

**III.15.2.9.1. Self-Supplied Capacity Eligibility.**

Where all or a portion of a resource is designated as a Self-Supplied Capacity Resource, it shall also maintain its status as a Generating Capacity Resource, Import Capacity Resource, or Distributed Energy Capacity Resource and must satisfy the Annual Capacity Auction qualification process requirements set forth in the remainder of Section III.15.2 applicable to that resource type, in addition to the requirements of this Section III.15.2.9.1. Where a Capacity Offer composed of separate resources is submitted for a Self-Supplied Capacity Resource, all of the requirements and deadlines specified in Section III.15.2.8 shall apply to that offer, in addition to the requirements of this Section III.15.2.9. The total quantity of capacity that a load serving entity designates as self-supplied capacity

may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period, which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied Capacity Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

**III.15.2.9.2. Locational Requirements for Self-Supplied Capacity Resources.**

In order to participate in the Annual Capacity Auction as a Self-Supplied Capacity Resource for a load in an import-constrained Capacity Zone, the Self-Supplied Capacity Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied Capacity Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Annual Capacity Auction as a Self-Supplied Capacity Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied Capacity Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

**III.15.2.10. Publication of Annual Qualified Capacity Values for Annual Capacity Auction.**

The ISO shall provide Annual Qualified Capacity values to Lead Market Participants of each Capacity Resource participating in an Annual Capacity Auction one business day before the opening of the Annual Capacity Auction Offer Window.

**III.15.2.11. Publication of Offer Information.**

(a) For each Capacity Offer, the quantity and Load Zone (or interface, as applicable) in which the resource is located will be published to the ISO's website no later than 15 days after the Annual Capacity Auction is conducted.

(b) For Capacity Offers from Import Capacity Resources, the name of submitter, quantity, and interface shall be published to the ISO's website no later than 15 days after the Annual Capacity Auction is conducted.

(c) The name of each Lead Market Participant submitting Capacity Offers, as well as the number of Capacity Offers submitted by each Lead Market Participant, shall be published to the ISO's website no later than 15 calendar days after the issuance of Advisory Qualified Capacity Values. Authorized Persons

of Authorized Commissions will be provided confidential access to full information about posted Capacity Offers upon request pursuant to Section 3.3 of the ISO New England Information Policy.

**III.15.3. Capacity Resource Accreditation.**

Pursuant to the provisions of this Section III.15.3, the ISO shall determine a summer Qualified Capacity, a winter Qualified Capacity, an Annual Qualified Capacity and, where applicable, a Monthly Qualified Capacity for each Generating Capacity Resource, Import Capacity Resource, Demand Capacity Resource, and Distributed Energy Capacity Resource. A Capacity Resource's Seasonal Qualified Capacity Values shall not exceed its seasonal Capacity Network Resource Interconnection Service or equivalent, or Capacity Network Import Interconnection Service, as applicable. Qualified Capacity for resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall not exceed the resource's highest previously received Capacity Supply Obligation unless the resource has demonstrated and qualified the additional capacity pursuant to Section III.15.2.4.1.

Qualified Capacity values for resources that have never previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall be calculated pursuant to Section III.15.3.1. Qualified Capacity for resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall be calculated pursuant to Sections III.15.3.2 through III.15.3.5.

**III.15.3.1. Qualified Capacity for Resources Never Previously Counted as Capacity.**

**III.15.3.1.1. Resources Never Previously Counted as Capacity**.

The summer and winter Qualified Capacity of a Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or is otherwise treated as such pursuant to the terms of this Section III.15, shall be determined in accordance with the capacity demonstration requirements set forth in Section III.15.2.6, as specified below.

To determine the Seasonal Qualified Capacity Values of a Generating Capacity Resource that is not an Intermittent Power Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant to Section III.15.2.6(c)(i), the ISO shall use the Section III.1.5.1.2(c) audit results. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3 and III.15.3.2.4, respectively.

To determine the Seasonal Qualified Capacity Values of a Generating Capacity Resource that is an Intermittent Power Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant Section III.15.2.6(c)(ii), the ISO shall use the Section III.1.5.1.3 audit results. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3 and Section III.15.3.2.4, respectively.

To determine the Seasonal Qualified Capacity Values of an Active Demand Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(iii), the ISO shall use the Section III.1.5.1.3.1 audit results. To determine the Seasonal Qualified Capacity Values of a Demand Capacity Resource other than an Active Demand Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(iv), the ISO shall use the Section III.15.7.1.5.4 audit results. The annual and Monthly Qualified Capacity of such resources shall be determined pursuant to Sections III.15.3.4.2 and III.15.3.4.3, respectively.

To determine the Seasonal Qualified Capacity Values of a Distributed Energy Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(v), the ISO shall use the audit results specified therein for the corresponding asset type. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to III.15.3.5.2 and III.15.3.5.3, respectively.

To determine the Seasonal Qualified Capacity Values of an Import Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant Section III.15.2.6(c)(vi), the ISO shall use the performance data results specified therein. The annual and monthly Qualified Capacity of such a resource shall be determined pursuant to III.15.3.3.

To determine the Seasonal Qualified Capacity Values of a resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and that has elected to demonstrate commercial capacity pursuant Section III.15.2.6(d), the ISO shall use the values developed pursuant to Section III.15.2.6(d). The annual Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3, Section III.15.3.4.2, or Section III.15.3.5.2, as applicable to

the relevant resource type. The Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.4, III.15.3.4.3, or Section III.15.3.5.3, as applicable to the relevant resource type.

**III.15.3.2 Qualified Capacity for Generating Capacity Resources.**

The summer, winter, annual, and monthly Qualified Capacity for Generating Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.2.

**III.15.3.2.1. Summer Qualified Capacity.**

(a) For the purpose of Annual Capacity Auction qualification, the summer Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the Capacity Demonstration Deadline each year, with only positive summer ratings included in the median calculation. Where a Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Generating Capacity Resource shall be equal to the median of all the Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the Capacity Demonstration Deadline of each year, with only positive summer ratings included in the median calculation.

(b) For the purpose of Annual Capacity Auction qualification, the summer Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the average of the median of the Intermittent Power Resource's net output during Summer Intermittent Reliability Hours for each of the previous five summer periods. If there are fewer than five full summer periods since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation, the summer Qualified Capacity of such resource shall be the average of the median of the Intermittent Power Resource's net output during Summer Intermittent Reliability Hours in each of the previous summer periods, or portion thereof, since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation. The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which there was a system-wide Capacity Scarcity Condition, and for Intermittent Power Resources in an import-constrained Capacity Zone, all summer period hours in which there was a Capacity Scarcity Conditions in that Capacity Zone.

**III.15.3.2.2. Winter Qualified Capacity.**

(a) For the purpose of Annual Capacity Auction qualification, the winter Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the Capacity Demonstration Deadline of each year, with only positive winter ratings included in the median calculation. Where a Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Generating Capacity Resource shall be equal to the median of all the Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the Capacity Demonstration Deadline of each year, with only positive winter ratings included in the median calculation.

(b) For the purpose of Annual Capacity Auction qualification, the winter Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the average of the median of the Intermittent Power Resource's net output during Winter Intermittent Reliability Hours for each of the previous five summer periods. If there are fewer than five full summer periods since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation, the winter Qualified Capacity of such resource shall be the average of the median of the Intermittent Power Resource's net output during Winter Intermittent Reliability Hours in each of the previous winter periods, or portion thereof, since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation. The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which there was a system-wide Capacity Scarcity Condition, and for Intermittent Power Resources in an import-constrained Capacity Zone, all winter period hours in which there was a Capacity Scarcity Conditions in that Capacity Zone.

**III.15.3.2.3. Annual Qualified Capacity.**

The Annual Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The Annual Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

**III.15.3.2.4. Monthly Qualified Capacity.**

The Monthly Qualified Capacity of a Generating Capacity Resource shall be the resource's most recent Seasonal Claimed Capability value for the season applicable to the relevant month; for those Generating Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

**III.15.3.3. Qualified Capacity for Import Capacity Resources.**

The summer, winter, annual, and monthly Qualified Capacity of an Import Capacity Resource backed by an External Control Area shall be based on the values and data submitted during the qualification process, subject to ISO review and verification. The summer, winter, annual, and monthly Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be based on the data submitted during the qualification process, subject to ISO review and verification, and calculated based on the summer and winter Qualified Capacity of the resources underlying the Import Capacity Resource, in accordance with Sections III.15.3.2.1 and III.15.3.2.2.

**III.15.3.4. Qualified Capacity for Demand Capacity Resources.**

The summer, winter, annual, and monthly Qualified Capacity for Demand Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.4.

**III.15.3.4.1. Summer and Winter Qualified Capacity.**

(a) For Demand Capacity Resources composed of Energy Efficiency measures, the summer (or winter, as applicable) Qualified Capacity shall equal the sum of the summer (or winter, as applicable) demand reduction values of the installed Energy Efficiency measures as of the Capacity Demonstration Deadline (excluding any capacity that will retire or deactivate, or whose Measure Life will expire, prior to the start of the applicable season of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses).

(b) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the summer and winter Qualified Capacity shall equal the median of the resource's Seasonal DR Audit value or Passive DR Audit value from the five most recent years, for the relevant season, increased by average avoided peak transmission and distribution losses. Where a Demand Capacity Resource has fewer than five summer or winter Seasonal Audit Values, as applicable, then the summer (or winter) Qualified Capacity for that Demand Capacity Resource shall be equal to the median of all the resource's previous

summer (or winter) Seasonal Audit Values, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation.

**III.15.3.4.2. Annual Qualified Capacity.**

The Annual Qualified Capacity of a Demand Capacity Resource shall equal the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

**III.15.3.4.3 Monthly Qualified Capacity.**

The Monthly Qualified Capacity of a Demand Capacity Resource, other than a resource composed of Energy Efficiency measures, shall equal its most recent Seasonal DR Audit value or Passive DR Audit value for the season applicable to the relevant month; for those Demand Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

The Monthly Qualified Capacity of a Demand Capacity Resource composed of Energy Efficiency measures shall equal the most recently-determined summer or winter demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire, deactivate, or whose Measure Life will expire, prior to the start of the relevant Obligation Month, and increased by average avoided peak transmission and distribution losses).

**III.15.3.5. Qualified Capacity of Distributed Energy Capacity Resources.**

The summer, winter, annual, and monthly Qualified Capacity for Distributed Energy Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.5.

**III.15.3.5.1. Summer and Winter Qualified Capacity.**

The summer (or winter, as applicable) Qualified Capacity of a Distributed Energy Capacity Resource that is not an Intermittent Power Resource shall equal the median of the resource's summer (or winter) Seasonal Audit Value from the five most recent years, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation. Where a Distributed Energy Capacity Resource has fewer than five summer (or winter) Seasonal Audit Values, then the summer (or winter) Qualified Capacity for that Distributed Energy Capacity Resource shall be

equal to the median of the resource's previous summer (or winter) Seasonal Audit Values, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation.

The summer or winter Qualified Capacity of Distributed Energy Capacity Resources that are Intermittent Power Resources shall be determined in accordance with the rules for Generating Capacity Resources that are Intermittent Power Resources in Section III.15.3.2.

**III.15.3.5.2. Annual Qualified Capacity.**

Annual Qualified Capacity for a Distributed Energy Capacity Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, unless the Distributed Energy Capacity Resource is an Intermittent Power Resource, in which case the Annual Qualified Capacity shall be equal to the resource's summer Qualified Capacity.

**III.15.3.5.3. Monthly Qualified Capacity.**

The Monthly Qualified Capacity of a Distributed Energy Capacity Resource shall equal the most recent Seasonal DECR Audit for the season applicable to the relevant month; for those Distributed Energy Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

**III.15.3.6. Adjustment for Significant Decreases in Capacity.**

For a Generating Capacity Resource, Import Capacity Resource backed by an External Resource, Distributed Energy Capacity Resource, or Demand Capacity Resource, if the most recent summer Seasonal Claimed Capability rating, summer season Import Capacity Resource performance data submitted pursuant to Section III.15.2.1.1.1, summer Seasonal DECR Audit Value, summer Seasonal DR Audit Value, or summer Passive DR Audit Value as of the Annual Capacity Auction's Capacity Demonstration Deadline is below the resource's Qualified Capacity by more than the threshold defined in the following formula:

$$Threshold = min[max(10\% \times QC_{Summer}, 2\ MW), 10\ MW]$$

Where,

$QC_{Summer}$ = the resource's summer Qualified Capacity

then the Lead Market Participant must elect one of the two treatments set forth in this Section III.15.3.6 by the close of the Seasonal Qualified Capacity Challenge and Restoration Plan Submission Window. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.15.3.6(b) and fails to meet the associated requirements, then the treatment described in Section III.15.3.6(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Annual Capacity Auction only, to have the resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability rating, summer Seasonal DECR Audit Value, Seasonal DR Audit Value, or Passive DR Audit Value as of the Capacity Demonstration Deadline, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) A Lead Market Participant may elect: (i) to submit a restoration plan describing the measures that will be taken and showing that the Generating Capacity Resource, Import Capacity Resource backed by an External Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section III.15.3.2, Section III.15.3.3, Section III.15.3.4, or Section III.15.3.5 by the start of the relevant Capacity Commitment Period; and (ii) to have the Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.15.3.2, Section III.15.3.3, Section III.15.3.4, or Section III.15.3.5 for the Annual Capacity Auction. The ISO shall review submitted restoration plans in accordance with the requirements and timelines set forth in Section III.15.2.7.

### III.15.3.7. Resources Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where a Generating Capacity Resource (other than an Intermittent Power Resource), Demand Capacity Resource, or Import Capacity Resource has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.15.3, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, in accordance with Section III.15.2.8; or (ii) have its Annual Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

Where a Distributed Energy Capacity Resource (other than an Intermittent Power Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this

Section III.15.3, then that resource must have its Annual Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

**III.15.4. Annual Capacity Auction.**

**III.15.4.1 Capacity Offers.**

Lead Market Participants submitting Capacity Offers in the Annual Capacity Auction shall submit Capacity Offers for the Capacity Commitment Period associated with the Annual Capacity Auction as specified in this Section III.15.4.1.

(a) Each Capacity Offer shall be associated with a Capacity Resource for which an Annual Qualified Capacity value has been established for the Annual Capacity Auction through the Annual Capacity Auction qualification process set forth in Sections III.15.2 and III.15.3.

(b) Capacity Offers must be submitted during the Annual Capacity Auction Offer Window, the dates of which will be specified as published in the Capacity Auction Calendar. Capacity Offers are not considered final until the close of the Annual Capacity Auction Offer Window and may be amended or corrected as necessary until such time as the window closes.

(c) If a Lead Market Participant fails to submit a Capacity Offer for a resource subject to the requirements of Section III.A.22.1, the ISO shall enter a Capacity Offer for the resource into the Annual Capacity Auction in accordance with Section III.A.22.1(d).

(d) Each Capacity Offer must specify at least one price-quantity pair, which consists of one price, denominated in $/kW-month to an accuracy of at most three digits to the right of the decimal point, and a quantity value, expressed in MW to an accuracy of up to three decimal places. The Capacity Offer may specify up to ten price-quantity pairs, where each such pair represents the total amount of capacity offered from the Capacity Resource at the price specified. If more than one price-quantity pair is submitted, the price-quantity pairs must specify prices and quantity values in such a way that, when the price-quantity pairs are ordered from lowest price to highest price, the quantity value in each price-quantity pair increases with each successive, higher-priced price-quantity pair. The price-quantity pair with the greatest specified price must include the Capacity Resource's total Annual Qualified Capacity. The Capacity Offer must not contain any offer prices less than $0.00/kW-month or greater than the Capacity Auction Offer Price Cap, unless otherwise allowed pursuant to Section III.A.22.2.3 and subsection (e) of this Section III.15.4.1 or required by Section III.A.21 and subsection (f) of this Section III.15.4.1. The Capacity Offer must not specify a total MW quantity value that exceeds the Capacity Resource's Annual Qualified Capacity.

(e) A price-quantity pair in a Capacity Offer must not specify a price above the Capacity Offer Price Threshold, except under the following circumstances:

(i) the Lead Market Participant for the Capacity Resource submitted the price-quantity pair to the Internal Market Monitor as part of a Proposed Capacity Offer, pursuant to Section III.A.22.2.2;

(ii) the Internal Market Monitor determined an Allowable Capacity Offer Price relative to the price-quantity pair pursuant to Section III.A.22.2.3; and

(iii) the specified price in the Capacity Offer does not exceed the price specified in the price-quantity pair reviewed by the Internal Market Monitor.

(f) For capacity included in a Capacity Offer that is subject to a Capacity Offer Floor Price pursuant to Section III.A.21.3, the price specified must not be less than the Capacity Offer Floor Price.

(g) A Capacity Offer may specify a Rationing Minimum Limit up to which the offer may not be rationed and must be accepted or rejected in whole. Without such indication, offers shall be rationable up to the total MW quantity in the offer that is priced at or below the Capacity Offer Price Threshold, subject to the auction clearing constraint described in Section III.15.4.2.2(d). The lowest priced price-quantity pair in a Capacity Offer that specifies a Rationing Minimum Limit must specify a quantity value equal to or greater than the specified Rationing Minimum Limit. Notwithstanding the foregoing, a Capacity Offer for an Import Capacity Resource may only specify a Rationing Minimum Limit pursuant to this subsection (g) if the Import Capacity Resource is associated with an Elective Transmission Upgrade, as described in Section III.15.2.1.1.1.

(h) If the Capacity Offer specifies any price above the Capacity Offer Price Threshold, the Capacity Offer may elect to have the Above-Threshold Offer Segment be treated as rationable, subject to any Rationing Minimum Limit specified pursuant to subsection (g). Without such an election, the Above-Threshold Offer Segment will be treated as non-rationable and accepted or rejected in whole. Notwithstanding the foregoing, a Capacity Offer for an Import Capacity Resource may only elect rationability for the Above-Threshold Offer Segment pursuant to this subsection (h) if the Import

Capacity Resource is associated with an Elective Transmission Upgrade, as described in Section III.15.2.1.1.1.

(i) In order to give effect to a self-supply designation made by a load serving entity pursuant to Section III.15.2.9 for any portion of the Capacity Resource's Annual Qualified Capacity, the Capacity Offer for such resource must (i) identify the load serving entity for which its capacity will serve as self-supplied capacity and the MW quantity of self-supplied capacity and (ii) include a price-quantity pair with an offer price of $0.00/kW-month that includes the amount of such capacity, unless such capacity is subject to a Capacity Offer Floor Price. If the self-supplied capacity is subject to a Capacity Offer Floor Price, then the price specified in the price-quantity pair including the self-supplied capacity must equal the Capacity Offer Floor Price.

(j) A Capacity Offer for a Generating Capacity Resource with a contract to export capacity during the Capacity Commitment Period must specify an Export Offer Segment and the interface over which the Export Offer Segment will be exported.

(k) A Lead Market Participant for a Capacity Resource that is subject to delayed deactivation pursuant to Sections II.52 and II.53 shall not enter a Capacity Offer for any capacity supplied by the Capacity Resource that is subject to delayed deactivation. The ISO shall enter such Capacity Resource's capacity subject to delayed deactivation into the Annual Capacity Auction at a price of $0.00/kW-month.

(l) If a prior multi-year Capacity Supply Obligation and Capacity Clearing Price election for the Capacity Resource had been made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 for a Forward Capacity Auction, the Capacity Offer submitted for such Capacity Resource must include a price-quantity pair with an offer price of $0.00/kW-month that includes the total amount of the resource's capacity that cleared subject to such election.

**III.15.4.2. Conduct of the Annual Capacity Auction**.

The ISO shall determine Capacity Supply Obligations and Capacity Clearing Prices for the Capacity Commitment Period by conducting the Annual Capacity Auction as described in this Section III.15.4.2.

**III.15.4.2.1. Replacement of Specified Prices for Mitigation Purposes.**

After the Annual Capacity Auction Offer Window, the ISO shall replace specified prices in submitted Capacity Offers as necessary, pursuant to Section III.A.22.2.4(c). Any such adjusted Capacity Offers shall be inputs for the Annual Capacity Auction.

**III.15.4.2.2. Clearing of the Annual Capacity Auction.**

(a) In determining Capacity Supply Obligations and Capacity Clearing Prices, the ISO shall employ an optimization algorithm that is designed to maximize social surplus in order to clear Capacity Offers, capacity entered into the auction by the ISO as described in Section III.15.4.1(k), and any Proxy Capacity Offers against the capacity demand curves calculated in accordance with Section III.15.1.1. In clearing Capacity Offers, the optimization algorithm shall take into account, as applicable, the inputs and constraints set forth in this Section III.15.4.2.2.

(b) The optimization algorithm shall take into account the following: (i) all price-quantity pairs in Capacity Offers for the Annual Capacity Auction submitted pursuant to Section III.15.4.1, subject to any adjustments made pursuant to Section III.15.4.2.1 and the constraint described in subsection (c) of this Section III.15.4.2.1; (ii) any Rationing Minimum Limits and rationability elections specified in Capacity Offers pursuant to Section III.15.4.1(g) and Section III.15.4.1(h), respectively; (iii) capacity from a Capacity Resource subject to delayed deactivation pursuant to Sections II.52 and II.53 at a default price of $0.00/kW-month; (iv) the set of distinct Capacity Zones determined to be modeled in the Annual Capacity Auction pursuant to Section III.12.4; (v) the System-Wide Capacity Demand Curve calculated in accordance with Section 15.1.1.1; (vi) any Capacity Zone Demand Curves for import-constrained and export-constrained Capacity Zones, calculated in accordance with Sections 15.1.1.2 and 15.1.1.3, respectively; (vii) external interface limits calculated pursuant to Section III.12.10; and (viii) any Proxy Capacity Offers for the Annual Capacity Auction as determined pursuant to Section III.A.24.7, which shall be treated as non-rationable.

(c) The optimization algorithm shall not take into account price-quantity pairs in Capacity Offers that specify a price that exceeds the Capacity Auction Offer Price Cap.

(d) Capacity entered into the Annual Capacity Auction at a price of $0.00/kW-month shall clear the auction.

(e) A Capacity Offer that specifies a Rationing Minimum Limit pursuant to Section III.15.4.1(g) shall not clear at quantities less than the specified Rationing Minimum Limit, and Above-Threshold Offer

Segments that are non-rationable pursuant to Section III.15.4.1(h) shall not clear at quantities less than the MW quantity of the segment.

(f) For an Export Offer Segment specified in a Capacity Offer that indicates a Generating Capacity Resource's contract to export capacity over an external interface connected to an import-constrained Capacity Zone from another Capacity Zone, or over an external interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone, the ISO shall model the Export Offer Segment as though that quantity of capacity were located in the Capacity Zone where the external interface identified in the Capacity Offer is located and adjust Capacity Zone Demand Curves as necessary to reflect such modeling.

(g) In determining the clearing result that accounts for auction inputs and satisfies all applicable constraints, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including clearing results where a Capacity Offer with a specified price below the Capacity Clearing Price does not clear.

(h) Where the clearing of the Annual Capacity Auction either system-wide or in a single Capacity Zone results in a tie (that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs), the following rules shall apply in sequence, as necessary, to determine clearing: (i) if multiple Capacity Offers may be rationed, they will be rationed proportionately; and (ii) the Capacity Offer associated with the Lead Market Participant having the lower market share in the capacity auction shall be cleared.

(i) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be the price specified by the System-Wide Capacity Demand Curve for the system-wide capacity entered into the Annual Capacity Auction that maximizes social surplus. In no case, however, shall the Capacity Clearing Price for the Rest-of-Pool Capacity Zone be less than the highest price specified in an offer for capacity that clears the auction, excluding any capacity that, due to its specified price, would not have cleared but for the fact that it is located within an import-constrained Capacity Zone that has a cleared quantity of capacity equal to or less than the truncation point for the zone's Capacity Zone Demand Curve.

(j) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an import-constrained Capacity Zone shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the import-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the import-constrained Capacity Zone and that clears the auction.

(k) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the export-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Rest-of-Pool Zone; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

(l) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an export-constrained Capacity Zone that is a nested export-constrained Capacity Zone, shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the export-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

(m) The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for an import-constrained Capacity Zone shall not exceed the Capacity Auction Offer Price Cap. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

(n) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an interface between the New England Control Area and an external Control Area shall be equal to:

(i) if the quantity of capacity over the external interface that clears the auction is equal to the external interface limit for such interface, the highest price specified in a Capacity Offer for capacity that is supplied from a resource offering capacity over such external interface and that clears the auction; or

(ii) if the quantity of capacity over the external interface that clears the auction is less than the external interface limit for such interface, the Capacity Clearing Price for the Capacity Zone associated with the external interface.

**III.15.4.2.3. Results of the Annual Capacity Auction.**

(a) Annual Capacity Supply Obligations shall be awarded to Capacity Resources in accordance with the results of the Annual Capacity Auction clearing mechanics described in Section III.15.4.2.2. For Intermittent Power Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.15.2) shall be adjusted based on the winter Qualified Capacity as determined pursuant to Section III.15.3.2.2. Additional Capacity Supply Obligations may be awarded in accordance with Section III.15.4.2.4.

(b) The Capacity Clearing Prices in each Capacity Zone modeled in the Annual Capacity Auction shall be the clearing prices determined as a result of the Annual Capacity Auction clearing mechanics described in Section III.15.4.2.2.

**III.15.4.2.4. Additional Clearing of Auction in the Event of Cleared Proxy Offers.**

If any Proxy Capacity Offer entered into the Annual Capacity Auction clears and receives a Capacity Supply Obligation, the ISO shall conduct an additional run of the auction. This additional run shall use the same methodology described in Section III.15.4.2.2, except that the additional run shall (i) exclude all Proxy Capacity Offers and (ii) enter all other capacity that cleared in the primary run of the Annual Capacity Auction at a price of $0.00/kW-month. The additional run of the auction shall not affect the Capacity Clearing Prices of the primary run of the Annual Capacity Auction pursuant to Section III.15.4.2.2. Capacity (other than capacity still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receives a Capacity Supply Obligation as a result of the primary run of the Annual Capacity Auction shall be paid the Capacity

Clearing Price in the Capacity Zone associated with the capacity during the associated Capacity Commitment Period. Where the additional run of the auction procures additional capacity, that additionally procured capacity shall be paid the price resulting from the additional run in the Capacity Zone associated with that additional capacity during the associated Capacity Commitment Period, and such price shall be equal to or greater than the price resulting from the primary run of the Annual Capacity Auction in that Capacity Zone.

**III.15.4.3. Publication of Annual Capacity Auction Results.**

As soon as practicable after the Annual Capacity Auction is complete, the ISO shall publish the results of that Annual Capacity Auction publicly on its website, including the set of Capacity Zones modeled in the auction, the Capacity Clearing Prices in each of those Capacity Zones, and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. The published information shall identify Proxy Capacity Offers that cleared, if any, in the primary run of the Annual Capacity Auction.

**III.15.5. Monthly Reconfiguration Auctions.**

For each Capacity Commitment Period, the ISO shall conduct Monthly Reconfiguration Auctions as described in this Section III.15.5. Monthly Reconfiguration Auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in the Monthly Reconfiguration Auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Section III.15.5.1) to clear supply offers (i.e., offers to assume a Capacity Supply Obligation) and demand bids (i.e., bids to shed a Capacity Supply Obligation) for each Capacity Zone included in the reconfiguration auction. Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected. Resources that are able to meet the requirements in other Capacity Zones shall be allowed to clear to meet such requirements, subject to the constraints modeled in the auction.

**III.15.5.1. Capacity Zones Included in Monthly Reconfiguration Auctions.**

Each Monthly Reconfiguration Auction associated with a Capacity Commitment Period shall include each of, and only, the Capacity Zones and external interfaces modeled in the Annual Capacity Auction for that Capacity Commitment Period in accordance with Section III.15.4.2.2.

**III.15.5.2. Participation in Monthly Reconfiguration Auctions.**

Each supply offer and demand bid in a Monthly Reconfiguration Auction must be associated with a specific resource and must satisfy the requirements of this Section III.15.5.2. All resource types may submit supply offers and demand bids in reconfiguration auctions. In accordance with Section III.A.13.2, supply offers and demand bids submitted for Monthly Reconfiguration Auctions shall not be subject to mitigation by the Internal Market Monitor. Offers composed of separate resources may not participate in reconfiguration auctions. Resources with capacity subject to delayed deactivation pursuant to Sections II.52 and II.53 may not participate in reconfiguration auctions, unless otherwise authorized pursuant to the terms of a cost-of-service agreement of the type described in Section II.54.1. Participation in any reconfiguration auction is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of the offer and bid deadline. The offer and bid deadline for each Monthly Reconfiguration Auction shall be announced by the ISO no later than 10 Business Days prior to that deadline. Upon issuance of the monthly bilateral results for the associated Obligation Month, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that monthly auction, as calculated pursuant to this Section III.15.5.2.

**III.15.5.2.1. Supply Offers in Monthly Reconfiguration Auctions.**

(a) All supply offers in Monthly Reconfiguration Auctions shall be submitted by the Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, denominated in $/kW-month.

(b) A resource may not submit a supply offer for a Monthly Reconfiguration Auction unless a Monthly Qualified Capacity value has been established for the resource for the month associated with the Monthly Reconfiguration Auction pursuant to the qualification processes described in Sections III.15.2 and III.15.3.

(c) The amount of capacity up to which a resource may submit a supply offer in a Monthly Reconfiguration Auction shall be the difference (but in no case less than zero) between (i) the resource's Monthly Qualified Capacity for the month associated with the auction, as determined pursuant to Section III.15.3 during the most recent qualification process for the resource; and (ii) the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month.

**III.15.5.2.2. Demand Bids in Monthly Reconfiguration Auctions.**

(a) All demand bids in Monthly Reconfiguration Auctions shall be submitted by the Lead Market Participant and shall specify the amount of capacity bid in MW and the price, denominated in $/kW-month.

(b) To submit a demand bid in a Monthly Reconfiguration Auction, a resource must have a Capacity Supply Obligation for the month associated with that Monthly Reconfiguration Auction.

(c) Where capacity associated with a Self-Supplied Capacity Resource that cleared in the Annual Capacity Auction for the Capacity Commitment Period is offered in a Monthly Reconfiguration Auction, a resource acquiring a Capacity Supply Obligation in that Monthly Reconfiguration Auction shall not as a result become a Self-Supplied Capacity Resource.

(d) Each demand bid submitted to the ISO for a Monthly Reconfiguration Auction shall be no greater than the amount of the resource's capacity that is already obligated for the month associated with that Monthly Reconfiguration Auction as of the offer and bid deadline for the auction.

**III.15.5.3. Clearing Offers and Bids in Monthly Reconfiguration Auctions.**

All supply offers and demand bids are rationable and may be cleared in whole or in part in Monthly Reconfiguration Auctions.

**III.15.5.4. Conduct of Monthly Reconfiguration Auctions.**

Prior to each month in the Capacity Commitment Period, the ISO shall conduct a Monthly Reconfiguration Auction for whole-month capacity commitments during that month. For each Monthly Reconfiguration Auction, the ISO shall employ an optimization algorithm that is designed to maximize social surplus in order to clear the supply offers against demand bids submitted for the auction. The truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Section III.15.1.1.2 and Section III.15.1.1.3 and external interface limits established pursuant to Section III.12 shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in Monthly Reconfiguration Auctions.

**III.15.5.5. Adjustment to Capacity Supply Obligations**.

For each supply offer that clears in a Monthly Reconfiguration Auction, the resource's Capacity Supply Obligation for the month associated with the auction shall be increased by the amount of capacity that clears. For each demand bid that clears in a Monthly Reconfiguration Auction, the resource's Capacity Supply Obligation for the month associated with the auction shall be decreased by the amount of capacity that clears.

**III.15.6. Bilateral Capacity Contracts.**

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals~~,~~ and Capacity Load Obligation Bilaterals~~, and Capacity Performance Bilaterals~~ in accordance with this Section III.15.6, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation. To the extent necessary for the ISO's review and approval of any of the bilateral contracts described in this Section III.15.6, the ISO shall apply the Capacity Zones and external interfaces modeled as inputs and constraints in the Annual Capacity Auction for the applicable Capacity Commitment Period, as described in Section III.15.4.2.2. Resources with capacity subject to delayed deactivation pursuant to Sections II.52 and II.53 may not participate in Capacity Supply Obligation Bilaterals ~~or Capacity Performance Bilaterals~~, unless otherwise authorized pursuant to the terms of a cost-of-service agreement of the type described in Section II.54.1.

**III.15.6.1. Capacity Supply Obligation Bilaterals.**

A Capacity Transferring Resource having a Capacity Supply Obligation and seeking to shed that obligation may enter into a Capacity Supply Obligation Bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part, to a Capacity Acquiring Resource, or portion thereof, for a whole-month period during the Capacity Commitment Period, as described in this Section III.15.6.1.

**III.15.6.1.1. Terms of and Participation in Capacity Supply Obligation Bilaterals.**

(a) Capacity Supply Obligation Bilaterals are available for monthly periods, and a Capacity Supply Obligation Bilateral must be coterminous with a calendar month.

(b) The qualification of Capacity Acquiring Resources for participation in Capacity Supply Obligation Bilaterals is determined in the same manner as the qualification of resources submitting supply offers for Monthly Reconfiguration Auctions as specified in Section III.15.5.2.1(b). A resource that does not have a Monthly Qualified Capacity value established for the month covered by the Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that month.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the monthly Capacity Supply Obligation of the Capacity Transferring Resource. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the amount of unobligated Monthly Qualified Capacity of the Capacity Acquiring Resource for the month covered by the Capacity Supply Obligation Bilateral. For the purpose of this subsection (c), unobligated Monthly Qualified Capacity refers to the Monthly Qualified Capacity that was

determined pursuant to Section III.15.3 in the most recent qualification process for the resource prior to the submission of the Capacity Supply Obligation Bilateral to the ISO and that is not subject to a Capacity Supply Obligation.

(d) A resource, or a portion thereof, that has been designated as a Self-Supplied Capacity Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied Capacity Resource as a result of the transaction.

(e) Capacity Supply Obligation Bilaterals are allowed between a Capacity Transferring Resource and a Capacity Acquiring Resource that are located within different Capacity Zones and across external interfaces modeled as part of the Annual Capacity Auction for the Capacity Commitment Period of the relevant monthly period, subject to the transmission interface limits between Capacity Zones and external interface limits, as described in Section III.15.6.1.4(b).

(f) Participation in any Capacity Supply Obligation Bilateral is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of submission to the ISO.

**III.15.6.1.2. Timing of Submission and Prior Notification to the ISO.**

The Lead Market Participant for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Capacity Supply Obligation Bilaterals in the Capacity Auction Calendar. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

**III.15.6.1.3. Contents of Submission to the ISO.**

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, denominated in $/kW-

month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

**III.15.6.1.4. ISO Review.**

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral and shall reject the Capacity Supply Obligation Bilateral if any of the submission and participation requirements described in this Section III.15.6.1 are not met. For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.

(b) After the close of the submittal window, the ISO shall conduct a review to determine the deliverability of the submitted Capacity Supply Obligation Bilaterals. In its review, the ISO shall model as constraints the truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Sections III.15.1.1.2 and III.15.1.1.3 and external interface limits established pursuant to Section III.12 for the applicable Capacity Commitment Period. The ISO shall reject Capacity Supply Obligation Bilaterals that are not fully deliverable up to their specific MW values without violating transmission transfer limits between Capacity Zones or external transfer limits. Transactions will only be accepted or rejected in their entirety. The ISO shall approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected, the Lead Market Participant for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the basis for such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

**III.15.6.1.5. Approval.**

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource for the month covered by the Capacity Supply Obligation Bilateral shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply

Obligation of the Capacity Acquiring Resource for the month covered by the Capacity Supply Obligation Bilateral shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

**III.15.6.2. Capacity Load Obligations Bilaterals.**

A Capacity Load Obligation Transferring Participant seeking to shed its Capacity Load Obligation may enter into a Capacity Load Obligation Bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone to a Capacity Load Obligation Acquiring Participant seeking to acquire a Capacity Load Obligation, as described in this Section III.15.6.2.

**III.15.6.2.1. Terms of and Participation in Capacity Load Obligation Bilaterals.**

A Capacity Load Obligation Bilateral must be in whole calendar month increments, may not exceed one year in duration, and must begin and end within the same Capacity Commitment Period. A Capacity Load Obligation Transferring Participant will be permitted to transfer, and a Capacity Load Obligation Acquiring Participant will be permitted to acquire, a Capacity Load Obligation if after entering into a Capacity Load Obligation Bilateral and submitting related information to the ISO within the specified submittal time period, the ISO approves such Capacity Load Obligation Bilateral.

**III.15.6.2.2. Timing of Submission to the ISO.**

Either the Capacity Load Obligation Transferring Participant or the Capacity Load Obligation Acquiring Participant may submit a Capacity Load Obligation Bilateral to the ISO. All Capacity Load Obligation Bilaterals must be submitted to the ISO in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial daily settlements of payments and charges associated with the Annual Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 p.m. on the first Business Day of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

**III.15.6.2.3. Contents of Submission to the ISO.**

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following: (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant

and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

**III.15.6.2.4. ISO Review.**

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section III.15.6.2 are not met.

**III.15.6.2.5. Approval.**

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral.

~~**III.15.6.3. Capacity Performance Bilaterals.**~~

~~A resource's Capacity Performance Score during a Capacity Scarcity Condition may be adjusted by entering into a Capacity Performance Bilateral as described in this Section III.15.6.3.~~

~~**III.15.6.3.1. Terms of and Participation in Capacity Performance Bilaterals.**~~

~~If a resource has a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five-minute interval through a Capacity Performance Bilateral, so long as both resources were subject to the same Capacity Scarcity Condition. The Lead Market Participant for the transferring resource may submit a Capacity Performance Bilateral to the ISO assigning all or a portion of its Capacity Performance Score for such five-minute interval to the receiving resource. The Capacity Performance Bilateral must be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score.~~

~~**III.15.6.3.2. Timing of Submission to the ISO.**~~

~~A Capacity Performance Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Annual Capacity Market for the month associated with the Capacity~~

~~Performance Bilateral, a Capacity Performance Bilateral must be submitted to the ISO no later than 12:00 p.m. on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Capacity Performance Bilateral may be revised by the parties to the transaction throughout the resettlement process).~~

~~**III.15.6.3.3. Contents of Submission to the ISO.**~~

~~The submission of a Capacity Performance Bilateral to the ISO shall include the following: (i) the resource identification number for the resource transferring its Capacity Performance Score; (ii) the resource identification number for the resource receiving the Capacity Performance Score; (iii) the MW amount of Capacity Performance Score being transferred; and (iv) the specific five-minute interval or intervals for which the Capacity Performance Bilateral applies.~~

~~**III.15.6.3.4. ISO Review.**~~

~~The ISO shall review the information provided in the submission of the Capacity Performance Bilateral and shall reject the Capacity Performance Bilateral if any of the provisions of this Section III.15.6.3 are not met.~~

~~**III.15.6.3.5. Effect of Capacity Performance Bilateral.**~~

~~A Capacity Performance Bilateral does not affect either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Capacity Performance Bilateral is to modify the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Condition subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments as described in Section III.15.8.2.~~

**III.15.7. Obligations of Capacity Suppliers.**

Resources assuming a Capacity Supply Obligation through an Annual Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a Monthly Reconfiguration Auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.15.7 for each Capacity Commitment Period.

**III.15.7.1. Resources with Capacity Supply Obligations.**

A resource with a Capacity Supply Obligation assumed through an Annual Capacity Auction, Monthly Reconfiguration Auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements

of this Section III.15.7.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

**III.15.7.1.1. Generating Capacity Resources with Capacity Supply Obligations.**

**III.15.7.1.1.1. Energy Market Offer Requirements**.

(a) A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

(i) the sum of the Generating Capacity Resource's Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours; or

(ii) if the Generating Capacity Resource cannot meet the offer requirements in Section III.15.7.1.1.1(a)(i) due to physical design limits, then the resource shall be offered into the Day-Ahead Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.

(b) Notwithstanding the foregoing, if the Generating Capacity Resource is a Settlement Only Resource, it may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

**III.15.7.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.**

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect

the known capability of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.19.

**III.15.7.1.1.3. [Reserved.]**

**III.15.7.1.1.4. [Reserved.]**

**III.15.7.1.1.5. Additional Requirements for Generating Capacity Resources.**
Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1 and the requirement to provide to the ISO, upon request and as soon as practicable, confirmation of gas volume schedules sufficient to deliver the energy scheduled for each Generating Capacity Resource using natural gas; and

(c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures (except that Settlement Only Resources are not subject to outage requirements), provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

**III.15.7.1.2. Import Capacity Resources with Capacity Supply Obligations.**

**III.15.7.1.2.1. Energy Market Offer Requirements.**
A Market Participant with an Import Capacity Resource must offer one or more External Transactions to import energy in the Day-Ahead Energy Market and Real-Time Energy Market for every hour of each Operating Day at the same external interface that, in total, equal the resource's Capacity Supply Obligation, except that:

(a) the offer requirement does not apply to any hour in which any External Resource associated with an Import Capacity Resource is on an outage;
(b) the Day-Ahead Energy Market offer requirement does not apply to any hour in which the import transfer capability of the external interface is 0 MW, and;
(c) the Real-Time Energy Market offer requirement does not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which Coordinated Transaction Scheduling is implemented.

Each External Transaction submitted in the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

Each External Transaction submitted in the Real-Time Energy Market in accordance with Section III.1.10.7 must reference the associated Import Capacity Resource.

**III.15.7.1.2.2. Additional Requirements for Import Capacity Resources.**

A Market Participant with an Import Capacity Resource that is associated with an External Resource must:

(a) comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the External Resource's native Control Area, and;
(b) notify the ISO of all outages impacting the Capacity Supply Obligation of the Import Capacity Resource in accordance with the outage notification requirements in ISO New England Operating Procedure No. 5.

**III.15.7.1.3. Intermittent Power Resources with Capacity Supply Obligations.**

**III.15.7.1.3.1. Energy Market Offer Requirements**.

(a) Market Participants with Intermittent Power Resources that are Dispatchable Resources and have a Capacity Supply Obligation are required to submit offers in the Day-Ahead Energy Market consistent with the Market Participant's expectation of the output of the resource in Real-Time. Market Participants with non-dispatchable Intermittent Power Resources with a Capacity Supply Obligation may submit, but are not required to submit, offers into the Day-Ahead Energy Market. Market Participants are required to submit offers for Intermittent Power Resources with a Capacity Supply Obligation for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day-Ahead projections of output

shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

(b) Notwithstanding the foregoing, an Intermittent Power Resource that is a Settlement Only Resource may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

**III.15.7.1.3.2. [Reserved.]**

**III.15.7.1.3.3. Additional Requirements for Intermittent Power Resources**.
Intermittent Power Resources with Capacity Supply Obligations are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals (except that Intermittent Power Resources that are Settlement Only Resources need not comply with outage requirements).

**III.15.7.1.4. [Reserved.]**

**III.15.7.1.5. Demand Capacity Resources with Capacity Supply Obligations.**

**III.15.7.1.5.1. Energy Market Offer Requirements.**

(a) A Market Participant with an Active Demand Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers for its Demand Response Resources into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.15.7.1.5.1; for purposes of the following comparisons, the portion of Demand Reduction Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. The sum of the Demand Reduction Offers must be equal to or greater than the Active Demand Capacity Resource's Capacity Supply Obligation whenever the Demand Response Resources are

physically available. If the Demand Response Resources are physically available at a level less than the Active Demand Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers will equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet the following requirement:

(i) the sum of the Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time plus Minimum Reduction Time plus Minimum Time Between Reductions is less than or equal to 72 hours.

(b) Seasonal Peak Demand Capacity Resources and On-Peak Demand Capacity Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

**III.15.7.1.5.2. Requirement that Offers Reflect Accurate Demand Response Resource Operating Characteristics.**

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a Demand Response Resource associated with an Active Demand Capacity Resource must reflect the then-known operating characteristics of the resource. Consistent with Section III.1.10.9(d), Demand Response Resources must re-declare to the ISO any changes to offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.19.

**III.15.7.1.5.3. Additional Requirements for Demand Capacity Resources.**

(a) A Market Participant may not associate an Asset with a non-commercial Demand Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Demand Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) An Energy Efficiency measure may be added to an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource (other than one consisting of Load Management or Distributed Generation) until two years after the start of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation; provided, however, that a resource that qualified for a Forward Capacity Auction associated with a Capacity Commitment Period beginning on or before June 1, 2024 may install Energy Efficiency measures until May 31, 2027. Once an Energy Efficiency measure has been

associated with an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, the measure may not be transferred to a different resource.

(c) For purposes of confirming Capacity Market Commercial Operation as described in Section III.15.2.6, the ISO shall use a summer Seasonal DR Audit value or summer Passive DR Audit value to verify the capacity rating of a Demand Capacity Resource with summer Qualified Capacity. A winter Seasonal DR Audit value or winter Passive DR Audit value may only be used to verify the winter commercial capacity of a Demand Capacity Resource. The summer and winter commercial capacity of a Demand Capacity Resource consisting of Energy Efficiency measures may be verified in any month of the year.

(d) For Active Demand Capacity Resources, a summer Seasonal DR Audit value shall be established for use from April 1 through November 30 and a winter Seasonal DR Audit value shall be established for use from December 1 through March 31. The summer or winter Seasonal DR Audit value of an Active Demand Capacity Resource is equal to the sum of the like-season Seasonal DR Audit values of its constituent Demand Response Resources as determined pursuant to Section III.1.5.1.3.1. The Seasonal DR Audit value of an Active Demand Capacity Resource shall automatically update whenever a new Seasonal DR Audit value is approved for a constituent Demand Response Resource or with changes to the makeup of the constituent Demand Response Resources.

(e) On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources shall in addition: (i) comply with the ISO's measurement and verification requirements pursuant to Section III.15.2.1.1.2.1. and the ISO New England Manuals; and (ii) comply with the auditing and rating requirements as detailed in Sections III.15.7.1.5.4 and III.15.7.1.5.5 and the ISO New England Manuals.

(f) Active Demand Capacity Resources shall in addition: (i) comply with the measurement and verification requirements and the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures; and (ii) comply with the auditing and rating requirements as detailed in Section III.15.7.1.5.5 and the ISO New England Manuals.

**III.15.7.1.5.4. On-Peak Demand Capacity Resource and Seasonal Peak Demand Capacity Resource Auditing Requirements.**

(a) A summer Passive DR Audit value and a winter Passive DR Audit value must be established for each On-Peak Demand Capacity Resource and Seasonal Peak Demand Capacity Resource in every Capacity Commitment Period during which the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource has an annual or monthly Capacity Supply Obligation.

(b) Summer Passive DR Audit values shall be determined based on data for one or more months of the summer Passive DR Auditing Period (June through August). Winter Passive DR Audit values shall be determined based on data for one or more months of the winter Passive DR Auditing Period (December through January).

(c) Passive DR Audit values shall be made available to the Market Participant within 20 Business Days following the end of the period for which the audit value is determined by the ISO.

(d) The audit value of an On-Peak Demand Capacity Resource shall be determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the On-Peak Demand Capacity Resource during the Demand Resource On-Peak Hours.

(e) The audit value of a Seasonal Peak Demand Capacity Resource shall be determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the Seasonal Peak Demand Capacity Resource during the Demand Resource Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in a month during the Passive DR Auditing Period, performance during Demand Resource On-Peak Hours in that month may be used.

(f) Passive DR Audit values shall become effective one calendar day after being made available to the Market Participant and remain valid until the earlier of: (i) the next like-season Passive DR Audit value becomes effective or (ii) the end of the following Capability Demonstration Year.

(g) For On-Peak Demand Capacity Resources consisting of Energy Efficiency measures and Seasonal Peak Demand Capacity Resources consisting of Energy Efficiency measures, the ISO shall calculate a summer Passive DR Audit value and a winter Passive DR Audit value in each month of the year. For all other On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources,

a Market Participant may request that a summer or winter Passive DR Audit value be determined based on data for, respectively, a summer or winter month outside of the Passive DR Auditing Periods. Such an audit shall not satisfy the Passive DR Audit requirement.

**III.15.7.1.5.5. Additional Demand Capacity Resource Audits.**

The ISO may perform one or both of the following additional audits for a Demand Capacity Resource to establish or verify the capability of the Demand Capacity Resource and its underlying assets and measures.

(a) Level 1 Audit: the ISO shall establish the audit results by conducting a review of records of the Assets and measures to verify that the reported Assets and measures have been installed and are operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.

(b) Level 2 Audit: the ISO shall establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of the Assets and measures. Such an audit may include a random or select sample of facilities and measures.

A level 1 audit is not required to precede a level 2 audit. If the results of the audit indicate that the demand reduction capability of the Demand Capacity Resource is less than or greater than its most recent like-season Passive DR Audit value or Seasonal DR Audit value, then the Demand Capacity Resource's audit value shall be adjusted accordingly.

**III.15.7.1.6. DNE Dispatchable Generator.**

**III.15.7.1.6.1. Energy Market Offer Requirements**.

DNE Dispatchable Generators with a Capacity Supply Obligation must submit offers into the Day-Ahead Energy Market for the full amount of the resource's expected hourly physical capability as determined by the Market Participant. Market Participants with DNE Dispatchable Generators having a Capacity Supply Obligation must submit offers for the Real-Time Energy Market consistent with the characteristics of the resource. For purposes of calculating Real-Time NCPC Charges, DNE Dispatchable Generators shall have a generation deviation of zero.

### III.15.7.1.7. Distributed Energy Capacity Resources with Capacity Supply Obligations.

#### III.15.7.1.7.1. Energy Market Offer Requirements.

(a) A Market Participant with a Distributed Energy Capacity Resource having a Capacity Supply Obligation shall submit offers for its Distributed Energy Resource Aggregations into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.15.7.1.7.1; for purposes of the following comparisons, the portion of any Demand Reductions Offers or Baseline Deviation Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. The sum of the offers must be equal to or greater than the Distributed Energy Capacity Resource's Capacity Supply Obligation whenever the Distributed Energy Resource Aggregations are physically available. If the Distributed Energy Resource Aggregations are physically available at a level less than the Distributed Energy Capacity Resource's Capacity Supply Obligation, the sum of the offers must equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each offer from a Distributed Energy Resource Aggregation made into the Day- Ahead Energy Market shall also meet the following requirement:

(i) the sum of the resource's notification time plus start-up time plus Minimum Run Time (or Minimum Deviation Time or Minimum Reduction Time) plus Minimum Down Time (or Minimum Time Between Deviations or Minimum Time Between Reductions) is less than or equal to 72 hours.

(b) Notwithstanding the foregoing, if the Distributed Energy Capacity Resource comprises Settlement Only Distributed Energy Resource Aggregations, it is not obligated to submit Supply Offers into the Day-Ahead Energy Market and may not submit Supply Offers into the Real-Time Energy Market.

#### III.15.7.1.7.2. Requirement that Offers Reflect Accurate Distributed Energy Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the then-known capability of the resource.

**III.15.7.1.7.3. Additional Requirements for Distributed Energy Capacity Resources.**

Distributed Energy Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) A Market Participant may not associate an Asset with a non-commercial Distributed Energy Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Distributed Energy Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) Distributed Energy Capacity Resources shall comply with the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

(c) Distributed Energy Capacity Resources shall comply with the auditing and rating requirements as detailed in this Market Rule 1 and the ISO New England Manuals.

(d) For Distributed Energy Capacity Resources, the Seasonal DECR Audit Value shall be established pursuant to Section III.1.7.13.

**III.15.7.2. Resources without a Capacity Supply Obligation.**

A resource that does not have any Capacity Supply Obligation shall comply with the requirements in this Section III.15.7.2 and shall not be subject to the requirements set forth in Section III.15.7.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

**III.15.7.2.1. Generating Capacity Resources without a Capacity Supply Obligation.**

**III.15.7.2.1.1. Energy Market Offer Requirements.**

A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. A Generating Capacity Resource that is a

Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

**III.15.7.2.1.1.1. Day-Ahead Energy Market Participation.**

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offered energy clears in the Day-Ahead Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the operating day, including the obligation to follow ISO Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

**III.15.7.2.1.1.2. Real-Time Energy Market Participation.**

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Real-Time Energy Market. If any portion of the offered energy clears in the Real-Time Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Real-Time Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow ISO Dispatch Instructions. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

**III.15.7.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.**

Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;

(b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Generating Capacity Resources having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, are not subject to

the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

**III.15.7.2.2. Distributed Energy Capacity Resources without a Capacity Supply Obligation.**

**III.15.7.2.2.1. Energy Market Offer Requirements.**

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation is not required to submit offers for the resource into the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant with a Settlement Only Distributed Energy Resource Aggregation is not permitted to submit an offer for that resource into the Real-Time Energy Market.

**III.15.7.2.2.2. Day-Ahead Energy Market Participation.**

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation may submit an offer into the Day- Ahead Energy Market. If any portion of the offer clears in the Day-Ahead Energy Market, the entire offer, up to the maximum capability offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market so long as it is not a Settlement Only Distributed Energy Resource Aggregation.

**III.15.7.2.2.3. Real-Time Energy Market Participation.**

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation, that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit an offer in the Real-Time Energy Market so long as the resource is not a Settlement Only Distributed Energy Resource Aggregation, and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

**III.15.7.2.2.4. Additional Requirements for Distributed Energy Capacity Resources Having No Capacity Supply Obligation.**

Distributed Energy Capacity Resources without a Capacity Supply Obligation shall comply with the requirements in Section III.15.7.1.7.3.

**III.15.7.2.3. Intermittent Power Resources without a Capacity Supply Obligation.**

**III.15.7.2.3.1. Energy Market Offer Requirements**.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. An Intermittent Power Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

**III.15.7.2.3.2. Additional Requirements for Intermittent Power Resources.**

Intermittent Power Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals; and

(b) Operating Data collection requirements as detailed in the ISO New England Manuals.

**III.15.7.2.4. [Reserved.]**

**III.15.7.2.5. Demand Capacity Resources without a Capacity Supply Obligation.**

**III.15.7.2.5.1. Energy Market Offer Requirements.**

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

Seasonal Peak Demand Capacity Resources and On-Peak Demand Capacity Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

**III.15.7.2.5.1.1. Day-Ahead Energy Market Participation.**

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation may submit a Demand Reduction Offer into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer, up to the Maximum Reduction offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the

Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

**III.15.7.2.5.1.2. Real-Time Energy Market Participation**.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit a Demand Reduction Offer in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

**III.15.7.2.5.2. Additional Requirements for Demand Capacity Resources Having No Capacity Supply Obligation**.

Demand Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with Section III.15.7.1.5.3(a) and (b) and with the auditing and rating requirements described in Section III.15.7.1.5.5 and the ISO New England Manuals;

(b) for Active Demand Capacity Resources, complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) for Active Demand Capacity Resources, complying with outage requirements as detailed in the ISO New England Operating Procedures and ISO New England Manuals. Active Demand Capacity Resources having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

**III.15.7.3. Exporting Resources.**

A resource that is exporting capacity not subject to a Capacity Supply Obligation to an external Control Area shall comply with this Section III.15.7.3 and the ISO New England Manuals. Intermittent Power Resources and Demand Capacity Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7 and Section III.1.10.7.A, as applicable.

**III.15.7.4. ISO Requests for Energy.**

The ISO may request that an Active Demand Capacity Resource, a Generating Capacity Resource, or a Distributed Energy Capacity Resource having capacity that is not subject to a Capacity Supply Obligation provide energy for reliability purposes in the Real-Time Energy Market, but such resource shall not be obligated under this Section III.15 by such a request to provide energy from that capacity. If such resource does provide energy from that capacity, the resource shall be paid based on its most recent offer and is eligible for NCPC.

**III.15.7.4.1. Real-Time High Operating Limit.**

For purposes of facilitating ISO requests for energy under Section III.15.7.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

**III.15.8. Capacity Payments and Charges.**

Revenue in the Annual Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.15.8.1 and Capacity Performance Payments as described in Section III.15.8.2, adjusted as described in Section III.15.8.3 and Section III.15.8.4. Market Participants with a Capacity Load Obligation shall be subject to charges as described in Section III.15.8.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.15 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

**III.15.8.1. Capacity Base Payments**.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.15.8.1.1.

**III.15.8.1.1. Payments and Charges Reflecting Capacity Supply Obligations.**

Each resource that has: (i) cleared in an Annual Capacity Auction, except for the portion of resources designated as Self-Supplied Capacity Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.15.8.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Annual Capacity Auction**. For a resource whose offer has cleared in an Annual Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the

Forward Capacity Auction in which the offer cleared, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, and subject to the limitations set forth in Section III.15.2.1.3.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in a Monthly Reconfiguration Auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and the price associated with the Capacity Supply Obligation Bilateral.

**III.15.8.1.2 Export Capacity**

If there are any unobligated Export Offer Segments from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Annual Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows.

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$ ] x [Cleared MWs of Export Offer Segment]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$ ] x [Cleared MWs of Export Offer Segment]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.15.8.5.2.

**III.15.8.2. Capacity Performance Payments.**

**III.15.8.2.1. Definition of Capacity Scarcity Condition.**

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

**III.15.8.2.2. Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.**

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.15.8.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided

for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.15.8.2.2(c), for any On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.15.8.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(ii) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(iii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

(e) A Distributed Energy Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Metered Quantity for Settlement and Reserve Quantity for Settlement of all the components of its constituent Distributed Energy Resource Aggregations; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Based on the Real-Time operational coordination, the resource must follow any distribution system limitation and update its physical parameters accordingly. The Actual Capacity Provided cannot be less than zero.

(i) The Real-Time demand reduction of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response

Baseline of the Demand Response Asset or Distributed Energy Resource associated with the Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

**III.15.8.2.3. Capacity Balancing Ratio.**

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

provided, however, that the Capacity Balancing Ratio shall not exceed a value of 1.0.

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.15.8.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the

Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

**III.15.8.2.4. Capacity Performance Score.**

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Capacity Resource or a Seasonal Peak Demand Capacity Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

**III.15.8.2.5. Capacity Performance Payment Rate.**

The Capacity Performance Payment Rate shall be $3500/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

**III.15.8.2.6. Calculation of Capacity Performance Payments.**

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an

interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

**III.15.8.3. Monthly Capacity Payment and Capacity Stop-Loss Mechanism.**

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.15.8.3.1 and Section III.15.8.3.2 below.

**III.15.8.3.1. Monthly Stop-Loss.**

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the product of the applicable Capacity Auction Offer Price Cap multiplied by the resource's Capacity Supply Obligation for the Obligation Month.

**III.15.8.3.2. Annual Stop-Loss.**

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (ACAcp – ACAsp) – (12 months x ACAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

ACAcp = the Capacity Clearing Price for the relevant Annual Capacity Auction.

ACAsp = the Annual Capacity Auction Offer Price Cap for the relevant Annual Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.15.8.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.15.8.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.15.8.3.2(b).

**III.15.8.4. Allocation of Deficient or Excess Capacity Performance Payments.**

For ~~each type of~~ Capacity Scarcity Conditions as described in Section III.15.8.2.1 ~~and for each Capacity Zone~~, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a), ~~and~~ (b), and (c) below. ~~Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.~~

(a) If the sum of all Capacity Performance Payments to all resources subject to ~~the~~ a Capacity Scarcity Condition ~~in the Capacity Zone~~ in an Obligation Month is positive, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.15.8.3, the deficiency ~~will~~ shall be charged to resources in proportion to the sum of each such resource's ~~Capacity Supply Obligation~~positive Capacity Performance Score for the Obligation Month~~, excluding any resources subject to the stop-loss mechanism described in Section III.15.8.3 for the Obligation Month and excluding any resource, or portion thereof, consisting of Energy Efficiency measures. If the charge described in this Section III.15.8.4(a) causes a resource to reach the stop-loss limit described in Section III.15.8.3, then the stop-loss cap described in Section III.15.8.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.15.8.4(a)~~.

(b) If the sum of all Capacity Performance Payments to all resources subject to ~~the~~ a Capacity Scarcity Condition ~~in the Capacity Zone~~ in an Obligation Month is negative, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.15.8.3, the excess ~~will~~

shall be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.15.8.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.15.8.3, and the remaining excess shall ~~will~~ be further allocated to other resources in the same manner as described in this Section III.15.8.4(b).

(c) If a deficiency of Capacity Performance Payments exists due to one or more resources reaching the stop-loss limit described in Section III.15.8.3, the deficiency shall be charged to all resources subject to a Capacity Scarcity Condition in an Obligation Month that have not reached their stop-loss limit (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. If the charge described in Section III.15.8.4(a) or the charge described in this Section III.15.8.4(c) causes a resource to reach the stop-loss limit described in Section III.15.8.3, then the stop-loss limit described in Section III.15.8.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.15.8.4(c).

**III.15.8.5. Charges to Market Participants with Capacity Load Obligations.**

**III.15.8.5.1. Calculation of Capacity Charges.**

For purposes of this Section III.15.8.5.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in rate component (b) of Sections III.15.8.5.1.1 through III.15.8.5.1.8 shall be divided by the number of days in the month to derive a daily settlement value.

**III.15.8.5.1.1. Annual Capacity Auction Charge.**

The ACA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone ACA Costs divided by Zonal Capacity Obligation.

Where:

Capacity Zone ACA Costs, for each Capacity Zone, are the Total ACA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total ACA Costs are the sum of, for all Capacity Zones, Capacity Supply Obligations in each zone (the total obligation awarded to resources in the Annual Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.15.8.5.1.5) multiplied by the applicable clearing price from the auction in which the obligation was awarded to the resource.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

**III.15.8.5.1.2. Monthly Reconfiguration Auction Charge.**

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where:

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the Monthly Reconfiguration Auction in each zone and the applicable Monthly Reconfiguration Auction clearing price, minus the sum of, for all Capacity Zones, any Capacity Supply Obligations shed through the Monthly Reconfiguration Auction in each zone and the applicable Monthly Reconfiguration Auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

**III.15.8.5.1.3. HQICC Capacity Charge.**

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where:

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections III.15.8.5.1.1(b), III.15.8.5.1.2(b), III.15.8.5.1.5(b), III.15.8.5.1.6(b), III.15.8.5.1.7(b), and III.15.8.5.1.8(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

**III.15.8.5.1.4. Self-Supply Adjustment.**

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where:

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied Capacity Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections III.15.8.5.1.1.(b), III.15.8.5.1.2(b), III.15.8.5.1.5(b), III.15.8.5.1.6(b), III.15.8.5.1.7(b) and III.15.8.5.1.8(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

**III.15.8.5.1.5. Intermittent Power Resource Capacity Adjustment.**

The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where:

Intermittent Power Resource Seasonal Variance is the difference between the ACA payments for Intermittent Power Resources in the Obligation Month and the base ACA payments for Intermittent Power Resources.

ACA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to Intermittent Power Resources in the Annual Capacity Auction process for the Obligation Month pursuant to Section III.15.4.2.3, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base ACA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Annual Qualified Capacity procured from Intermittent Power Resources in the Annual Capacity Auction process, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Zonal Capacity Obligation in all Capacity Zones.

**III.15.8.5.1.6. CTR Transmission Upgrade Charge.**

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where:

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.15.8.5.4.1(f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

**III.15.8.5.1.7. CTR Pool-Planned Unit Charge.**

The CTR Pool-Planned Unit charge is: (a) the total Capacity Load Obligation in all Capacity Zones less the amount of any CTRs specifically allocated pursuant to Section III.15.8.5.4.2, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.15.8.5.4.2.

Where:

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.15.8.5.4.2(b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

**III.15.8.5.1.8. Multi-Year Rate Election Adjustment.**

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where:

Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that were terminated pursuant to Section III.13.3.4A or Section III.15.A.2.1, or withdrawn pursuant to Section III.15.A.2.3), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where:

Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that were terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

**III.15.8.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.**

The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation prior to the commencement of each Obligation Month for each Capacity Zone established in the Annual Capacity Auction pursuant to Section III.12.4. The Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

The Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year one year prior to the start of the Capacity Commitment Period to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year one year prior to the start of the Capacity Commitment Period.

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; when all load of a Distributed Energy Resource Aggregation participating as a Storage DARD is load associated with the receipt of electricity from the grid for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each day of the month and each Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above and (ii) the ratio of the sum of the load serving entity's daily Coincident Peak Contributions, to the sum of all load serving entities' daily Coincident Peak Contributions in that Capacity Zone.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each day of the month and each Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied Capacity Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource, Demand Response Resource, or a Demand Response Distributed Energy Resource Aggregation.

**III.15.8.5.2.1. Charges Associated with Dispatchable Asset Related Demands.**

Dispatchable Asset Related Demand resources will not receive Annual Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

**III.15.8.5.3. Excess Revenues**.

Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section III.13.3.4A or Section III.15.A.2.1, or withdrawn pursuant to Section III.15.A.2.3, shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

**III.15.8.5.4. Capacity Transfer Rights.**

**III.15.8.5.4.1. Specifically Allocated CTRs Associated with Transmission Upgrades.**

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.15.8.5.1.6.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.15.8.5.1.6.

(e) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine export interface for as long as Casco Bay continues to pay to support the transmission upgrades.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price in the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price in the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. This value will be divided by the number of days in the month to derive a daily settlement value.

**III.15.8.5.4.2. Specifically Allocated CTRs for Pool-Planned Units.**

(a) In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive for each Capacity Commitment Period an allocation of CTRs for each such unit that is the product of: (i) the MW quantity of capacity that the unit cleared in the Annual Capacity Auction associated with the Capacity Commitment Period; and (ii) the municipal utility's ownership entitlements in such unit. The CTRs

allocated pursuant to this Section may be designated as self-supply quantities as described in Section III.15.2.9. Municipal utility ownership entitlements are set as shown in the table below and are not transferrable.

| | Millstone 3 | Seabrook | Stonybrook GT 1A | Stonybrook GT 1B | Stonybrook GT 1C | Stonybrook 2A | Stonybrook 2B | Wyman 4 |
|---|---|---|---|---|---|---|---|---|
| Danvers | 0.2627% | 1.1124% | 8.4569% | 8.4569% | 8.4569% | 11.5551% | 11.5551% | 0.0000% |
| Georgetown | 0.0208% | 0.0956% | 0.7356% | 0.7356% | 0.7356% | 1.0144% | 1.0144% | 0.0000% |
| Ipswich | 0.0608% | 0.1066% | 0.2934% | 0.2934% | 0.2934% | 0.0000% | 0.0000% | 0.0000% |
| Marblehead | 0.1544% | 0.1351% | 2.6840% | 2.6840% | 2.6840% | 1.5980% | 1.5980% | 0.2793% |
| Middleton | 0.0440% | 0.3282% | 0.8776% | 0.8776% | 0.8776% | 1.8916% | 1.8916% | 0.1012% |
| Peabody | 0.2969% | 1.1300% | 13.0520% | 13.0520% | 13.0520% | 0.0000% | 0.0000% | 0.0000% |
| Reading | 0.4041% | 0.6351% | 14.4530% | 14.4530% | 14.4530% | 19.5163% | 19.5163% | 0.0000% |
| Wakefield | 0.2055% | 0.3870% | 3.9929% | 3.9929% | 3.9929% | 6.3791% | 6.3791% | 0.4398% |
| Ashburnham | 0.0307% | 0.0652% | 0.6922% | 0.6922% | 0.6922% | 0.9285% | 0.9285% | 0.0000% |
| Boylston | 0.0264% | 0.0849% | 0.5933% | 0.5933% | 0.5933% | 0.9120% | 0.9120% | 0.0522% |
| Braintree | 0.0000% | 0.6134% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| Groton | 0.0254% | 0.1288% | 0.8034% | 0.8034% | 0.8034% | 1.0832% | 1.0832% | 0.0000% |
| Hingham | 0.1007% | 0.4740% | 3.9815% | 3.9815% | 3.9815% | 5.3307% | 5.3307% | 0.0000% |
| Holden | 0.0726% | 0.3971% | 2.2670% | 2.2670% | 2.2670% | 3.1984% | 3.1984% | 0.0000% |
| Holyoke | 0.3194% | 0.3096% | 0.0000% | 0.0000% | 0.0000% | 2.8342% | 2.8342% | 0.6882% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Hudson | 0.1056% | 1.6745% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.3395% |
| Hull | 0.0380% | 0.1650% | 1.4848% | 1.4848% | 1.4848% | 2.1793% | 2.1793% | 0.1262% |
| Littleton | 0.0536% | 0.1093% | 1.5115% | 1.5115% | 1.5115% | 3.0607% | 3.0607% | 0.1666% |
| Mansfield | 0.1581% | 0.7902% | 5.0951% | 5.0951% | 5.0951% | 7.2217% | 7.2217% | 0.0000% |
| Middleborough | 0.1128% | 0.5034% | 2.0657% | 2.0657% | 2.0657% | 4.9518% | 4.9518% | 0.1667% |
| North Attleborough | 0.1744% | 0.3781% | 3.2277% | 3.2277% | 3.2277% | 5.9838% | 5.9838% | 0.1666% |
| Pascoag | 0.0000% | 0.1068% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| Paxton | 0.0326% | 0.0808% | 0.6860% | 0.6860% | 0.6860% | 0.9979% | 0.9979% | 0.0000% |
| Shrewsbury | 0.2323% | 0.5756% | 3.9105% | 3.9105% | 3.9105% | 0.0000% | 0.0000% | 0.4168% |
| South Hadley | 0.5755% | 0.3412% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| Sterling | 0.0294% | 0.2044% | 0.7336% | 0.7336% | 0.7336% | 1.1014% | 1.1014% | 0.0000% |
| Taunton | 0.0000% | 0.1003% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| Templeton | 0.0700% | 0.1926% | 1.3941% | 1.3941% | 1.3941% | 2.3894% | 2.3894% | 0.0000% |
| Vermont Public Power Supply Authority | 0.0000% | 0.0000% | 2.2008% | 2.2008% | 2.2008% | 0.0000% | 0.0000% | 0.0330% |
| West Boylston | 0.0792% | 0.1814% | 1.2829% | 1.2829% | 1.2829% | 2.3041% | 2.3041% | 0.0000% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Westfield | 1.1131% | 0.3645% | 9.0452% | 9.0452% | 9.0452% | 13.5684% | 13.5684% | 0.7257% |

Allocation of CTRs as described in this Section shall expire on December 31, 2040. If a unit listed in the table above retires prior to December 31, 2040, however, allocation of CTRs for such unit shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Annual Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant (collectively, "WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) For any CTRs specifically allocated pursuant to this Section that are not designated self-supply quantities for the Capacity Commitment Period, the municipal utility entitlement holder shall receive a credit reflecting the value of such remaining CTRs. The value of each remaining CTR shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located; and (ii) the remaining MW quantity. This value will be divided by the number of days in the month to derive a daily settlement value.

**III.15.8.5.5. Annual Capacity Market Net Charge Amount.**

The Annual Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charges; (b) its revenues from any applicable specifically allocated CTRs; and (c) any applicable export charges.

**III.15.9. Information Publication and Reporting.**

**III.15.9.1. Publication of Certain Data Prior to the Annual Capacity Auction.**

For each Annual Capacity Auction, no later than one Business Day before the opening of the Annual Capacity Auction Offer Window, the ISO shall publish publicly on its website:

a. which Capacity Zones shall be modeled in the Annual Capacity Auction;
b. the transmission interface limits as determined pursuant to Section III.12.5;
c. which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Annual Capacity Auction;
d. determinations on which new resources have been rejected due to deliverability impacts pursuant to Section III.15.2.3;
e. the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Annual Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;
f. for each resource that submitted a Load-Side Relationship Certification, the following information: the resource technology type; which qualifying circumstance in Section III.A.21.1.4 was asserted in the Load-Side Relationship Certification; the relevant state policy asserted in the Load-Side Relationship Certification, if any; whether the ISO accepted or rejected the Load-Side Relationship Certification; and, consequently, whether the resource was subject to a review for the exercise of buyer-side market power; and
g. which resources are qualified to participate in the Annual Capacity Auction, including resource type, Capacity Zone, and Annual Qualified Capacity.

**III.15.9.2. Publication of Certain Data After Conducting the Annual Capacity Auction**

In addition to the Annual Capacity Auction results information identified by Section III.15.2.11 and Section III.15.4.3 of Market Rule 1, within 15 days of conducting the Annual Capacity Auction, the ISO shall publish publicly on its website:

a. which Capacity Offers, satisfying the requirements of Section III.A.21.1 of Market Rule 1, were not reviewed for an exercise of buyer-side market power because of one of the conditions described in Sections III.A.21.1.1, III.A.21.1.2, or III.A.21.1.4 of Market Rule 1; and the condition met by each such resource;
b. the Internal Market Monitor's determinations made as part of any buyer-side market power review conducted pursuant to Section III.A.21.2 and any Capacity Offer Floor Price determinations made pursuant to Section III.A.21.3 with regard to capacity not previously cleared

in an Annual Capacity Auction or Forward Capacity Auction, and the basis for any such determinations; except that offer price information and any information employed by the Internal Market Monitor in making these determinations related to the potential impact of a Capacity Resource's offer on Capacity Clearing Prices shall not be published publicly;

c. the Internal Market Monitor's determinations regarding Proposed Capacity Offers, including whether the Internal Market Monitor accepted or rejected prices specified in a resource's Proposed Capacity Offer that were subject to Internal Market Monitor review and whether the Internal Market Monitor accepted or rejected the cost components of the resource' offer, which are set forth in Section III.A.22.2.3(a). No offer prices, cost components, or other underlying data shall be published; and,

d. which resources offering capacity not previously offered into an Annual Capacity Auction or Forward Capacity Auction were qualified to participate in the Annual Capacity Auction (this information will include a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations).

## 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:

**Above-Threshold Offer Segment** is the total MW quantity of a Capacity Offer that is priced above the Capacity Offer Price Threshold, whether such MW quantity is delimited by only one price-quantity pair or multiple price-quantity pairs submitted as part of the Capacity Offer pursuant to Section III.15.4.1.

**Active Demand Capacity Resource** is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward or Annual Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 or Section III.15 of Market Rule 1.

**Actual Capacity Provided** is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 or Section III.15.8.2.2 of Market Rule 1.

**Actual Load** is the consumption at the Retail Delivery Point for the hour.

**Additional Resource Blackstart O&M Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Additional Resource Specified-Term Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Additional Resource Standard Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Administrative Costs** are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

**Administrative Export De-List Bid** is a bid 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.

**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.

**Advisory Qualified Capacity Values** are the advisory summer and winter Qualified Capacity values, calculated pursuant to Section III.15.2.5.

**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.

**Allowable Capacity Offer Price** is a price determined by the Internal Market Monitor as part of its review of Proposed Capacity Offers pursuant to Section III.A.22.2.3.

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

**Alternative Technology Regulation Resource (ATRR)** is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

**Ancillary Services** are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

**Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount** are defined in Section IV.B.2.2 of the Tariff.

**Annual Capacity Auction (ACA)** is the Annual Capacity Market auction process carried out pursuant to Section III.15.4 of Market Rule 1.

**Annual Capacity Auction Cleared Export Transaction** is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

**Annual Capacity Auction Offer Window** is the period described in the Capacity Auction Calendar during which Capacity Offers must be submitted for an Annual Capacity Auction.

**Annual Capacity Market** is the annual market for procuring capacity in the New England Control Area, as set forth in Section III.15 of Market Rule 1.

**Annual Qualified Capacity** is the Qualified Capacity calculated pursuant to Section III.15.3 that is used in an Annual Capacity Auction.

**Annual Transmission Revenue Requirements** are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

**Annual Reconfiguration Transaction** is a bilateral transaction associated with the Forward Capacity Market that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

**Applicants**, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

**Application** is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

**Asset** is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, a Distributed Energy Resource participating as part of a Demand Response Distributed Energy Resource Aggregation, a Settlement Only Distributed Energy Resource Aggregation, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

**Asset Registration Process** is the ISO business process for registering an Asset.

**Asset Related Demand** is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration; (2) a Storage DARD with a consumption capability of at least 0.1 MW; or (3) one or more storage facilities that are not Electric Storage Facilities with an aggregate consumption capability of at least 1 MW.

**Asset Related Demand Bid Block-Hours** are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

**Asset-Specific Going Forward Costs** are the net costs of an asset that is part of a Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Generating Capacity Resources as described in Section III.A.22 (for an asset associated with a Capacity Offer price subject to Internal Market Monitor review) or Section III.A.24 (for an asset submitting a Deactivation Notification).

**Assigned Meter Reader** reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

**Auction Revenue Right (ARR)** is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

**Auction Revenue Right Allocation (ARR Allocation)** is defined in Section 1 of Appendix C of Market Rule 1.

**Auction Revenue Right Holder (ARR Holder)** is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

**Authorized Commission** is defined in Section 3.3 of the ISO New England Information Policy.

**Authorized Person** is defined in Section 3.3 of the ISO New England Information Policy.

**Automatic Response Rate** is the response rate, in MW/Minute, at which a Market Participant is willing to have a Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

**Available Energy** is a value that reflects the MWhs of energy available from an Electric Storage Facility for economic dispatch.

**Available Storage** is a value that reflects the MWhs of unused storage available from an Electric Storage Facility for economic dispatch of consumption.

**Average Hourly Load Reduction** is either: (i) the sum of the On-Peak Demand Capacity Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Capacity Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.15.2.1.1.2.1 or Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

**Average Hourly Output** is either: (i) the sum of the On-Peak Demand Capacity Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Capacity Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 or Section III.15.2.1.1.2.1 of Market Rule 1 and the ISO New England Manuals.

**Backstop Transmission Solution** is a solution proposed: (i) to address a reliability 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.

**Benchmark Scenario** is an Economic Study reference scenario that is described in Section 17.2(a) of Attachment K to the OATT.

**Bilateral Contract (BC)** is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

**Bilateral Contract Block-Hours** are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

**Binary Storage DARD** is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Binary Storage Facility** is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Blackstart Capability Test** is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

**Blackstart Capital Payment** is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

**Blackstart Equipment** is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

**Blackstart O&M Payment** is the annual Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

**Blackstart Owner** is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

**Blackstart Service** is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

**Blackstart Service Commitment** is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

**Blackstart Service Minimum Criteria** are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

**Blackstart Standard Rate Payment** is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

**Blackstart Station** is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

**Blackstart Station-specific Rate Payment** is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

**Blackstart Station-specific Rate Capital Payment** is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the

provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

**Block** is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day); and (8) with respect to Day-Ahead Ancillary Services Offers administered by the ISO, a quantity with a related price for Day-Ahead Ancillary Services (Day-Ahead Ancillary Services Offers may contain multiple prices for each hour).

**Block-Hours** are the number of Blocks administered for a particular hour.

**Budget and Finance Subcommittee** is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

**Business Day** is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

**Cancelled Start NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Capability Demonstration Year** is the one year period from September 1 through August 31.

**Capacity Acquiring Resource** is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 or Section III.15.6.1, or; (2) a reconfiguration auction, as described in Section III.13.4 or Section III.15.5.

**Capacity Auction Calendar** is a calendar published on the ISO's website, as described in Section III.15, detailing dates and deadlines associated with Annual Capacity Market participation, Monthly Reconfiguration Auction participation, and monthly Capacity Supply Obligation Bilateral transactions.

**Capacity Auction Offer Price Cap** is determined pursuant to Section III.15.1.2.1 of Market Rule 1 prior to the Annual Capacity Auction for each Capacity Commitment Period and is the highest price at which capacity may be offered into the Annual Capacity Auction, unless otherwise expressly allowed by the Tariff.

**Capacity Balancing Ratio** is a ratio used in calculating the Capacity Performance Payment in the Capacity Market, as described in Section III.13.7.2.3 or III.15.8.2.3 of Market Rule 1.

**Capacity Base Payment** is the portion of revenue received in the Forward Capacity Market or Annual Capacity Market as described in Section III.13.7.1 or Section III.15.8.1 of Market Rule 1.

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

**Capacity Clearing Price** is the clearing price in 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 or resulting from the Annual Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.15.4.2.

**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 and Annual 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 Demonstration Deadline** is a monthly deadline described in the Capacity Auction Calendar for completion of the capacity demonstration requirement set forth in Section III.15.2.6 prior to participation in the Annual Capacity Auction, a Monthly Reconfiguration Auction, or a Capacity Supply Obligation Bilateral transaction.

**Capacity Export Through Import Constrained Zone Transaction** is defined in Section III.1.10.7(f)(i) of Market Rule 1.

**Capacity Load Obligation** is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 or Section III.15.8.5.2 of Market Rule 1.

**Capacity Load Obligation Acquiring Participant** is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 or Section III.15.6.2 of Market Rule 1.

**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 or Section III.15.6 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 or Section III.15.6.2 of Market Rule 1.

**Capacity Market** is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1, or the annual market for procuring capacity in the New England Control Area, as described in Section III.15 of Market Rule 1.

**Capacity Market Commercial Operation** is defined in Section III.15.2.6 of Market Rule 1.

**Capacity Market Deactivation** is the permanent removal of a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource from the Capacity Market, or the permanent reduction in Capacity Network Import Capability of an External Elective Transmission Upgrade, as described in Section II.I of the OATT.

**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 Network Resource (CNR)** is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

**Capacity Network Resource Interconnection Service** (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

**Capacity Offer** is an offer submitted for inclusion in the Annual Capacity Auction as set forth in Section III.15.4.1 of Market Rule 1.

**Capacity Offer Floor Price** is defined in Section III.A.21.3 of Market Rule 1.

**Capacity Offer Price Threshold (COPT)** is the price specified in Section III.A.22.2.1 of Market Rule 1 associated with the submission, review, and mitigation of prices specified in Capacity Offers submitted for the Annual Capacity Auction.

**Capacity Offer Review Submission Deadline** is the deadline described in the Capacity Auction Calendar by which proposed Capacity Offers and accompanying documentation must be submitted to the Internal Market Monitor in accordance with Section III.A.22.2.2.

**Capacity Performance Payment** is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 or Section III.15.8.2 of Market Rule 1.

**Capacity Performance Payment Rate** is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 or Section III.15.8.2.5 of Market Rule 1.

**Capacity Resource** is a type of resource eligible to participate in the Annual Capacity Auction. There are four types of Capacity Resources: Generating Capacity Resource, Import Capacity Resource, Demand Capacity Resource, and Distributed Energy Capacity Resource.

**Capacity Performance Score** is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 or Section III.15.8.2.4 of Market Rule 1.

**Capacity Rationing Rule** addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

**Capacity Scarcity Condition** is a period during which performance is measured in the Capacity Market, as described in Section III.13.7.2.1 or III.15.8.7.2.1 of Market Rule 1.

**Capacity Supply Obligation** is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2 or an Annual Capacity Auction in accordance with Section III.15.4, a reconfiguration auction in accordance with Section III.13.4 or Section III.15.5, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 or Section III.15.6.1 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 or Section III.15.6.1 of Market Rule 1.

**Capacity Transfer Rights (CTRs)** are calculated in accordance with Section III.13.7.5.4 or Section III.15.8.5.4.

**Capacity Transferring Resource** is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 or Section III.15.6.1, or; (2) a reconfiguration auction, as described in Section III.13.4 or Section III.15.5.

**Capacity Zone** is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

**Capacity Zone Demand Curves** are the demand curves used in the Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3 and in Sections III.15.1.1.2 and III.15.1.1.3.

**Capital Funding Charge (CFC)** is defined in Section IV.B.2 of the Tariff.

**CARL Data** is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

**Category B Designated Blackstart Resource** has the same meaning as Designated Blackstart Resource.

**Charge** is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

**CLAIM10** is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

**CLAIM30** is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

**Claimed Capability Audit** is performed to determine the real power output capability of a Generator Asset, the demand reduction capability of a Demand Response Resource, or the demand reduction capability and energy injection capability of a Demand Response Distributed Energy Resource Aggregation.

**Cluster** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**Cluster Enabling Transmission Upgrade (CETU)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Entry Deadline** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Interconnection System Impact Study (CSIS)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Request Window** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**Cluster Restudy** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**Cluster Study** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**CNR Capability** is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

**Coincident Peak Contribution** is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

**Commercial Capacity** is capacity that has achieved FCM Commercial Operation or Capacity Market Commercial Operation.

**Commission** is the Federal Energy Regulatory Commission.

**Commitment Period** is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

**Common Costs** are those costs associated with a Station that are avoided only if none of the Generating Capacity Resources composing the Station acquire a Capacity Supply Obligation for the Capacity

Commitment Period, or by the acceptance of the Deactivation Notification of all Generating Capacity Resources composing 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 Capacity Market Transaction** is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction or Annual Capacity Auction in which multiple Lead Market Participants provide capacity, as described in Section III.13.1.5 or Section III.15.2.8 of Market Rule 1.

**Composite Offer Deadline** is the deadline for submission of the Composite Offer Form described at Section III.15.2.8.

**Composite Offer Form** is a form submitted by Lead Market Participants for separate resources seeking to participate as a single composite Capacity Resource in the Annual Capacity Auction, as described in Section III.15.2.8.

**Confidential Information** is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

**Confidentiality Agreement** is Attachment 1 to the ISO New England Billing Policy.

**Congestion** is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

**Congestion Component** is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

**Congestion Cost** is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

**Congestion Paying LSE** is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

**Congestion Revenue Fund** is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

**Congestion Shortfall** means congestion payments exceed congestion charges during the billing process in any billing period.

**Continuous Storage ATRR** is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage DARD** is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage Generator Asset** is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage Facility** is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Control Agreement** is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

**Control Area** is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and
(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

**Controllable Behind-the-Meter Generation** means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

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

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

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

**Cost-Based Reference Price** is a price determined by the Internal Market Monitor for comparison to a price in a Proposed Capacity Offer submitted pursuant to Section III.A.22.2.3.

**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 and for each Annual Capacity Auction pursuant to Section III.15.1.2.

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

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

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

**Credit Qualifying** means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

**Credit Threshold** consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

**Critical Energy Infrastructure Information (CEII)** is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

**Current Ratio** is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

**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.

**Cyber Security Exigency** is a suspicious or malicious electronic act or event that compromises or attempts to compromise, or disrupts or attempts to disrupt, the ongoing operation of the ISO, the New England Markets, or reliability within the New England Control Area or other electrical facilities directly or indirectly connected to the New England Transmission System and (i) whose severity or nature reasonably requires that the ISO obtain expert assistance not normally called upon to counter such an electronic act or resolve such an event or (ii) whose nature requires the ISO to report such an electronic act or event pursuant to NERC Critical Infrastructure Protection Reliability Standards or applicable regulations promulgated by the Department of Homeland Security, the Department of Energy, or a federal agency with similar cybersecurity responsibilities (or any of their respective successor organizations or agencies).

**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)(1) of Market Rule 1.

**Day-Ahead Ancillary Services** means Day-Ahead Flexible Response Services and Day-Ahead Energy Imbalance Reserve.

**Day-Ahead Ancillary Services Avoidable Input Cost** is defined in Section III.A.8.2.2 of Appendix A of Market Rule 1.

**Day-Ahead Ancillary Services Benchmark Level** is defined in Section III.A.8.2 of Appendix A of Market Rule 1.

**Day-Ahead Ancillary Services Offer Block-Hours** are Block-Hours assigned to the Lead Market Participant for each Day-Ahead Ancillary Services Offer. Blocks of the Day-Ahead Ancillary Services Offer in effect for each hour will be totaled to determine the quantity of Day-Ahead Ancillary Services Offer Block-Hours for a given day.

**Day-Ahead Ancillary Services Expected Close-Out Component** is defined in Section III.A.8.2.1 of Appendix A of Market Rule 1.

**Day-Ahead Ancillary Services Market** means the sale of and payment for Day-Ahead Ancillary Services developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

**Day-Ahead Ancillary Services Offer** is an offer that may be submitted by Market Participants in the Day-Ahead Ancillary Services Market in accordance with Section III.1.8.1 of Market Rule 1, and that is used by the ISO to determine obligations for Day-Ahead Ancillary Services as described in Section III.3.2.1(a)(2) of Market Rule 1.

**Day-Ahead Ancillary Services Strike Price** is specified in Section III.1.8.2 of Market Rule 1.

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

**Day-Ahead Demand Reduction Obligation** is defined in Section III.3.2.1(a)(1) of Market Rule 1.

**Day-Ahead Energy Imbalance Reserve** is a form of reserve capability that is procured in the Day-Ahead Ancillary Services Market to help satisfy the Forecast Energy Requirement Demand Quantity described in Section III.1.8.4 of Market Rule 1.

**Day-Ahead Energy Imbalance Reserve Obligation** is defined in Section III.3.2.1(a)(2) of Market Rule 1.

**Day-Ahead Energy Market** means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

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

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

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

**Day-Ahead 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 Flexible Response Services** means Day-Ahead Ten-Minute Spinning Reserve, Day-Ahead Ten-Minute Non-Spinning Reserve, and Day-Ahead Thirty-Minute Operating Reserve.

**Day-Ahead Flexible Response Services Demand Quantities** means Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, Day-Ahead Total Ten-Minute Reserve Demand Quantity, Day-Ahead Minimum Total Reserve Demand Quantity, and Day-Ahead Total Reserve Demand Quantity.

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

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

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

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

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

**Day-Ahead Market** means the jointly optimized Day-Ahead Energy Market and Day-Ahead Ancillary Services Market.

**Day-Ahead Minimum Total Reserve Demand Quantity** is described in Section III.1.8.3(c) of Market Rule 1.

**Day-Ahead Prices** means the prices resulting from the Day-Ahead Market as described in Section III.2.6 of Market Rule 1.

**Day-Ahead Ten-Minute Non-Spinning Reserve** is a form of ten-minute reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

**Day-Ahead Ten-Minute Non-Spinning Reserve Obligation** is defined in Section III.3.2.1(a)(2) of Market Rule 1.

**Day-Ahead Ten-Minute Spinning Reserve** is a form of ten-minute reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

**Day-Ahead Ten-Minute Spinning Reserve Demand Quantity** is described in Section III.1.8.3(a) of Market Rule 1.

**Day-Ahead Ten-Minute Spinning Reserve Obligation** is described in Section III.3.2.1(a)(2) of Market Rule 1.

**Day-Ahead Thirty-Minute Operating Reserve** is a form of reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

**Day-Ahead Thirty-Minute Operating Reserve Obligation** is defined in Section III.3.2.1(a)(2) of Market Rule 1.

**Day-Ahead Total Ten-Minute Reserve Demand Quantity** is described in Section III.1.8.3(b) of Market Rule 1.

**Day-Ahead Total Reserve Demand Quantity** is described in Section III.1.8.3(d) of Market Rule 1.

**DDP Dispatchable Resource** is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

**Deactivation Notification** is a notification of the planned New England Market Deactivation or Capacity Market Deactivation of a resource, External Elective Transmission Upgrade, or portion thereof, submitted to the ISO by the applicable Lead Market Participant.

**Deactivation Notification Deadline** is the deadline for submission of a Deactivation Notification and a Deactivation Notification Package, as discussed in Section II.52.1 of the OATT.

**Deactivation Notification Package** is information submitted to the ISO, as specified in Section II.52.3 of the OATT, by a resource or External Elective Transmission Upgrade seeking a determination regarding a Deactivation Notification.

**Debt-to-Total Capitalization Ratio** is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

**Decrement Bid** means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

**Default Amount** is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

**Default Period** is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

**Delivering Party** is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

**Demand Bid** means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

**Demand Bid Block-Hours** are the Block-Hours assigned to the submitting Customer for each Demand Bid.

**Demand Bid Cap** is $2,000/MWh.

**Demand Capacity Resource** is a type of resource that may participate in the Capacity Market. There are three Demand Capacity Resource types: Active Demand Capacity Resource, On-Peak Demand Capacity Resource, and Seasonal Peak Demand Capacity Resource.

**Demand Designated Entity** is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

**Demand Reduction Offer** is an offer by a Market Participant with a Demand Response Resource to reduce demand.

**Demand Reduction Offer Block-Hours** are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

**Demand Reduction Threshold Price** is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

**Demand Resource On-Peak Hours** are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

**Demand Resource Seasonal Peak Hours** are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

**Demand Response Asset** is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

**Demand Response Available** is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

**Demand Response Baseline** is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

**Demand Response Holiday** is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

**Demand Response Distributed Energy Resource Aggregation (DRDERA)** is a type of Distributed Energy Resource Aggregation that is described in additional detail in Section III.6.5.

**Demand Response Resource** is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

**Demand Response Resource Notification Time** is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

**Demand Response Resource Ramp Rate** is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

**Demand Response Resource Start-Up Time** is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

**Designated Agent** is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20 Service Provider, an Eligible Customer, or a Transmission Customer.

**Designated Blackstart Resource** is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

**Designated Entity** is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

**Designated FCM Participant** is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

**Designated FTR Participant** is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

**Desired Dispatch Point (DDP)** means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

**Direct Assignment Facilities** are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

**Directly Metered Assets** are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

**Disbursement Agreement** is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

**Dispatch Instruction** means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

**Dispatch Zone** means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

**Dispatchable Asset Related Demand (DARD)** is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

**Dispatchable Resource** is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

**Dispute Representatives** are defined in 6.5.c of the ISO New England Billing Policy.

**Disputed Amount** is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

**Disputing Party**, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

**Distributed Energy Capacity Resource (DECR)** is a type of Capacity Resource that participates in the Capacity Market and composes one or more Distributed Energy Resource Aggregations.

**Distributed Energy Resource (DER)** is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation, or demand reduction.

**Distributed Energy Resource Aggregation (DERA)** is an aggregation of Distributed Energy Resources that is registered under Section III.6.7 and is described in additional detail in Section III.6.

**Distributed Energy Resource Aggregator (DER Aggregator)** is a Market Participant that aggregates one or more Distributed Energy Resources for participation in a Distributed Energy Resource Aggregation and serves as the Lead Market Participant for a Distributed Energy Resource Aggregation.

**Distributed Generation** means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

**DRR Aggregation Zone** is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

**Do Not Exceed (DNE) Dispatchable Generator** is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

**Do Not Exceed Dispatch Point** is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

**Dynamic De-List Bid** is a bid submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, Existing Demand Capacity Resources, and Existing Distributed Energy Capacity

Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

**Dynamic De-List Bid Threshold** is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

**EA Amount** is defined in Section IV.B.2.2 of the Tariff.

**Early Amortization Charge (EAC)** is defined in Section IV.B.2 of the Tariff.

**Early Amortization Working Capital Charge (EAWCC)** is defined in Section IV.B.2 of the Tariff.

**Early Payment Shortfall Funding Amount (EPSF Amount)** is defined in Section IV.B.2.4 of the Tariff.

**Early Payment Shortfall Funding Charge (EPSFC)** is defined in Section IV.B.2 of the Tariff.

**EAWW Amount** is defined in Section IV.B.2.3 of the Tariff.

**EBITDA-to-Interest Expense Ratio** is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

**Economic Dispatch Point** is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

**Economic Maximum Limit or Economic Max** is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must

maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

**Economic Minimum Limit or Economic Min** is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

**Economic Study or Economic Studies** are studies conducted by the ISO pursuant to the process set out in Section 17 of Attachment K to the OATT.

**Effective Offer** is the Supply Offer, Demand Reduction Offer, Demand Bid or Day-Ahead Ancillary Services Offer that is used for NCPC calculation purposes as specified in Section III.F.1(a).

**EFT** is electronic funds transfer.

**Elective Transmission Upgrade** is defined in Section I of Schedule 25 of the OATT.

**Elective Transmission Upgrade Interconnection Customer** is defined in Schedule 25 of the OATT.

**Electric Reliability Organization (ERO)** is defined in 18 C.F.R. § 39.1.

**Electric Storage Facility** is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

**Eligible Customer** is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

**Eligible FTR Bidder** is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

**Emergency** is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

**Emergency Condition** means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

**Emergency Energy** is energy transferred from one control area operator to another in an Emergency.

**Emergency Minimum Limit or Emergency Min** means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

**EMS** is energy management system.

**End-of-Round Price** is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

**End User Participant** is defined in Section 1 of the Participants Agreement.

**Energy** is power produced in the form of electricity, measured in kilowatthours or megawatthours.

**Energy Administration Service (EAS)** is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

**Energy Component** means the Locational Marginal Price at the reference point.

**Energy Efficiency** is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

**Energy Imbalance Service** is the form of Ancillary Service described in Schedule 4 of the OATT.

**Energy Market** is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

**Energy Non-Zero Spot Market Settlement Hours** are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

**Energy Offer Floor** is negative $150/MWh.

**Energy Transaction Units (Energy TUs)** are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, Day-Ahead Ancillary Services Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

**Equipment Damage Reimbursement** is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

**Equivalent Demand Forced Outage Rate (EFORd**) means the portion of time a unit is in demand, but is unavailable due to forced outages.

**Establish Claimed Capability Audit** is the audit performed pursuant to Section III.1.5.1.2.

**Excepted Transaction** is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

**Existing Capacity Qualification Deadline** is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

**Existing Capacity Qualification Package** is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

**Existing Capacity Resource** is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

**Existing Capacity Retirement Deadline** is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

**Existing Capacity Retirement Package** is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

**Existing Demand Capacity Resource** is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

**Existing Distributed Energy Capacity Resource** is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.2 of Market Rule 1.

**Existing Generating Capacity Resource** is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

**Existing Import Capacity Resource** is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

**Expedited Study Request** is defined in Section II.34.7 of the OATT.

**Export-Adjusted LSR** is as defined in Section III.12.4(b)(ii).

**Export Bid** is a bid 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.

**Export Offer Segment** is the total MW quantity of a Capacity Offer that is subject to a contract to export capacity outside the New England Control Area during the Capacity Commitment Period associated with the Capacity Offer, whether such MW quantity is delimited by only one price-quantity pair or multiple price-quantity pairs submitted as part of the Capacity Offer pursuant to Section III.15.4.1.

**Exports** are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

**External Elective Transmission Upgrade (External ETU)** is defined in Section I of Schedule 25 of the OATT.

**External Market Monitor** means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

**External Node** is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

**External Resource** means a generation resource located outside the metered boundaries of the New England Control Area.

**External Transaction** is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

**External Transaction Cap** is $2,000/MWh for External Transactions other than Coordinated External Transactions and $1,000/MWh for Coordinated External Transactions.

**External Transaction Floor** is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative $1,000/MWh for Coordinated External Transactions.

**External Transmission Project** is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

**Facilities Study** is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected

PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

**Facility and Equipment Testing** means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

**Failure to Maintain Blackstart Capability** is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

**Failure to Perform During a System Restoration** is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

**Fast Start Demand Response Resource** is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

**Fast Start Generator** means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

**FCA Qualified Capacity** is the Qualified Capacity that is used in a Forward Capacity Auction.

**FCM Capacity Charge Requirements** are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

**FCM Charge Rate** is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

**FCM Commercial Operation** is defined in Section III.13.3.8 of Market Rule 1.

**FCM Deposit** is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

**FCM Financial Assurance Requirements** are described in Section VII of the ISO New England Financial Assurance Policy.

**Final Forward Reserve Obligation** is calculated in accordance with Section III.9.8(a) of Market Rule 1.

**Financial Assurance Default** results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

**Financial Assurance Obligations** relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

**Financial Transmission Right (FTR)** is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

**Firm Point-To-Point Service** is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

**Firm Transmission Service** is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

**Flexible DNE Dispatchable Generator** is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

**Force Majeure** - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20 Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20 Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20 Service Provider, or any other Transmission Owner, in the case of a Schedule 20 Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20 Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20 Service Provider, or any Transmission Owner.

**Forecast Energy Requirement Demand Quantity** is described in Section III.1.8.4 of Market Rule 1.

**Forecast Energy Requirement Penalty Factor** is a rate, in $/MWh, that is used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of forecast energy requirement shortages and is defined in Section III.2.6.2(d) of Market Rule 1.

**Forecast Energy Requirement Price** is determined in accordance with Section III.2.6.2(b) of Market Rule 1.

**Forward Capacity Auction (FCA)** is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1. The final Forward Capacity Auction was for the Capacity Commitment Period beginning on June 1, 2027.

**Forward Capacity Auction Starting Price** is calculated in accordance with Section III.13.2.4 of Market Rule 1.

**Forward Capacity Market (FCM)** is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

**Forward Energy Inventory Election** is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

**Forward LNG Inventory Election** is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

**Forward Reserve** means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

**Forward Reserve Assigned Megawatts** is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

**Forward Reserve Auction** is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

**Forward Reserve Auction Offers** are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

**Forward Reserve Charge** is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

**Forward Reserve Clearing Price** is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

**Forward Reserve Credit** is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

**Forward Reserve Delivered Megawatts** are calculated in accordance with Section III.9.6.5 of Market Rule 1.

**Forward Reserve Delivery Period** is defined in Section III.9.1 of Market Rule 1.

**Forward Reserve Failure-to-Activate Megawatts** are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

**Forward Reserve Failure-to-Activate Penalty** is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

**Forward Reserve Failure-to-Activate Penalty Rate** is specified in Section III.9.7.2 of Market Rule 1.

**Forward Reserve Failure-to-Reserve**, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

**Forward Reserve Failure-to-Reserve Megawatts** are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

**Forward Reserve Failure-to-Reserve Penalty** is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

**Forward Reserve Failure-to-Reserve Penalty Rate** is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

**Forward Reserve Fuel Index** is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

**Forward Reserve Heat Rate** is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

**Forward Reserve Market** is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

**Forward Reserve MWs** are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

**Forward Reserve Obligation** is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

**Forward Reserve Obligation Charge** is defined in Section III.10.4 of Market Rule 1.

**Forward Reserve Offer Cap** is $7,100/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. As described in Section III.9.1, the final Forward Reserve Procurement Period shall run from October 1, 2024 through February 28, 2025.

**Forward Reserve Qualifying Megawatts** refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

**Forward Reserve Resource** is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

**Forward Reserve Threshold Price** is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

**FTR Auction** is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

**FTR Auction Revenue** is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

**FTR Credit Test Percentage** is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

**FTR Financial Assurance Requirements** are described in Section VI of the ISO New England Financial Assurance Policy.

**FTR Holder** is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

**FTR-Only Customer** is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

**FTR Settlement Risk Financial Assurance** is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

**GADS Data** means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

**Gap Request for Proposals (Gap RFP)** is defined in Section III.11 of Market Rule 1.

**Gas Day** means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

**Generating Capacity Resource** means a type of resource participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2..

**Generator Asset** is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

**Generator Imbalance Service** is the form of Ancillary Service described in Schedule 10 of the OATT.

**Generator Interconnection Related Upgrade** is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

**Generator Owner** is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

**Good Utility Practice** means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

**Governance Only Member** is defined in Section 1 of the Participants Agreement.

**Governance Participant** is defined in the Participants Agreement.

**Governing Documents**, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

**Governing Rating** is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

**Grandfathered Agreements (GAs)** is a transaction specified in Section II.45 for the applicable period specified in that Section.

**Grandfathered Intertie Agreement (GIA)** is defined pursuant to the TOA.

**Handy-Whitman Index of Public Utility Construction Costs** is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

**Highgate Transmission Facilities (HTF)** are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

**Host Participant or Host Utility** is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

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

**Hourly 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** is a type of resource participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2.

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

**Inadvertent Energy Revenue Charges or Credits** is defined in Section III.3.2.1(p) of Market Rule 1.

**Inadvertent Interchange** means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

**Increment Offer** means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

**Incremental ARR** is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

**Incremental ARR Holder** is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

**Incremental Cost of Reliability Service** is described in Section II.54.5 of the OATT..

**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.

**Initial State of Charge** is the State of Charge that an Electric Storage Facility offers at the start of hour one of the Day-Ahead Energy Market.

**Installed Capacity Requirement** means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

**Interchange Transactions** are transactions deemed to be effected under Market Rule 1.

**Interconnecting Transmission Owner** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Interconnection Agreement** is the "Large Generator Interconnection Agreement", the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement" pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

**Interconnection Customer** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Interconnection Procedure** is the "Large Generator Interconnection Procedures," the "Small Generator Interconnection Procedures," or the "Elective Transmission Upgrade Interconnection Procedures" pursuant to Schedules 22, 23, and 25 of the ISO OATT.

**Interconnection Reliability Operating Limit (IROL)** has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

**Interconnection Request** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

**Interconnection Rights Holder(s) (IRH)** has the meaning given to it in Schedule 20A to Section II of this Tariff.

**Interest** is interest calculated in the manner specified in Section II.8.3.

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

**Intermittent Power Resource** is a wind, solar, run of river hydro or other renewable resource or an aggregation of wind, solar, run of river hydro and other renewable resources that does not have control over its net power output.

**Internal Bilateral for Load** is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

**Internal Bilateral for Market for Energy** is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

**Internal Elective Transmission Upgrade (Internal ETU)** is defined in Section I of Schedule 25 of the OATT.

**Internal Market Monitor** means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

**Interregional Planning Stakeholder Advisory Committee (IPSAC)** is the committee described as such in the Northeast Planning Protocol.

**Interregional Transmission Project** is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

**Interruption Cost** is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

**Inventoried Energy Day** is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported

by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

**Investment Grade Rating,** for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

**Invoice** is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

**Invoice Date** is the day on which the ISO issues an Invoice.

**ISO** means ISO New England Inc.

**ISO Charges**, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

**ISO Control Center** is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

**ISO-Initiated Claimed Capability Audit** is the audit performed pursuant to Section III.1.5.1.4.

**ISO New England Administrative Procedures** means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

**ISO New England Billing Policy** is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

**ISO New England Filed Documents** means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

**ISO New England Financial Assurance Policy** is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

**ISO New England Information Policy** is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

**ISO New England Manuals** are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

**ISO New England Operating Documents** are the Tariff and the ISO New England Operating Procedures.

**ISO New England Operating Procedures (OPs)** are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

**ISO New England Planning Procedures** are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

**ISO New England System Rules** are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

**ITC Agreement** is defined in Attachment M to the OATT.

**ITC Rate Schedule** is defined in Section 3.1 of Attachment M to the OATT.

**ITC System** is defined in Section 2.2 of Attachment M to the OATT.

**ITC System Planning Procedures** is defined in Section 15.4 of Attachment M to the OATT.

**Joint ISO/RTO Planning Committee (JIPC)** is the committee described as such in the Northeastern Planning Protocol.

**Late Payment Account** is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

**Late Payment Account Limit** is defined in Section 4.2 of the ISO New England Billing Policy.

**Late Payment Charge** is defined in Section 4.1 of the ISO New England Billing Policy.

**Lead Market Participant,** for purposes other than the Forward Capacity Market or Annual Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids, Demand Reduction Offers, Baseline Deviation Offers, or Day-Ahead Ancillary Services 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. For purposes of the Annual Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of a Capacity Resource.

**Limited Energy Resource** means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

**Load Asset** means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

**Load Management** means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

**Load Shedding** is the systematic reduction of system demand by temporarily decreasing load.

**Load-Side Relationship Certification** is a certification described in Section III.A.21.1.4 that a Lead Market Participant submits as part of a submission of information pursuant to Section III.A.21.1.5 to demonstrate that certain capacity should not be subject to buyer-side market power review.

**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 Longer-Term Transmission Upgrade** is any addition, modification, and/or upgrade to the New England Transmission System with a voltage level below 115 kV that is required in connection with the

construction of a Longer-Term Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Section 16 of Attachment K to the OATT.

**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 115 kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

**Local Resource Adequacy Requirement** is calculated pursuant to Section III.12.2.1.1.

**Local Second Contingency Protection Resources** are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

**Local Service** is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

**Local Service Schedule** is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

**Local Sourcing Requirement (LSR)** is a value calculated as described in Section III.12.2.1 of Market Rule 1.

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

**Localized Costs** are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 and Section 10 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

**Location** is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

**Locational Marginal Price (LMP)** is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

**Long-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.

**Longer-Term Proposal** is a proposal submitted by a Qualified Transmission Project Sponsor pursuant to Section 16.4(b) of Attachment K to the OATT.

**Longer-Term Transmission Solution** is the Longer-Term Proposal identified as the preferred solution pursuant to Section 16 of Attachment K to the OATT.

**Longer-Term Transmission Study** is a study conducted by the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. The 2050 Transmission Study shall be the first Longer-Term Transmission Study.

**Longer-Term Transmission Upgrade** is an addition, modification, and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Longer-Term Transmission Upgrade PTF classification specified in the OATT and has been included in the Regional System Plan and RSP Project List as a Longer-Term Transmission Upgrade pursuant to the procedures described in Section 16 of Attachment K of the OATT.

**Loss Component** is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

**Loss of Load Expectation (LOLE)** is the probability of disconnecting non-interruptible customers due to a resource deficiency.

**Lost Opportunity Cost (LOC)** is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

**LSE** means load serving entity.

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

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

**Manual Response Rate** is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

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

**Marginal Reliability Impact** is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

**Market Credit Limit** is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

**Market Credit Test Percentage** is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

**Market 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 Service Agreement (MPSA)** is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

**Market Rule 1** is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

**Market Violation** is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

**Material Adverse Change** is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

**Material Adverse Impact** is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

**Maximum Capacity Limit** is a value calculated as described in Section III.12.2.2 of Market Rule 1.

**Maximum Consumption Limit** is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

**Maximum Daily Award Limit** is a parameter that may be submitted as part of a Day-Ahead Ancillary Services Offer, as described in Section III.1.8.1, that expresses the maximum total megawatt-hours of Day-Ahead energy offered or bid and Day-Ahead Ancillary Services offered for the next Operating Day.

**Maximum Daily Energy Limit** is the maximum amount of megawatt-hours that a Limited Energy Resource expects to be able to generate in the next Operating Day.

**Maximum Daily Consumption Limit** is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

**Maximum Facility Load** is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

**Maximum Interruptible Capacity** is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

**Maximum Load** is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

**Maximum Number of Daily Starts** is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

**Maximum Reduction** is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

**Maximum State of Charge** is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, above which the ISO shall not schedule the Electric Storage Facility to receive electricity from the grid.

**Measure Life** is the estimated time an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the

Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction, Annual Capacity Auction, or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

**Measurement and Verification Documents** mean the measurement and verification documents described in Section III.13.1.4.3.1 and Section III.15.2.1.1.2.1 of Market Rule 1 that are submitted by On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

**Measurement and Verification Plan** means the measurement and verification plan submitted by an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1, or as part of the qualification process for the Annual Capacity Auction pursuant to the requirements of Section III.15.2.1.1.2.1 of Market Rule 1, and the ISO New England Manuals.

**Measurement and Verification Reference Reports** are optional reports submitted by On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

**Measurement and Verification Summary Report** is the monthly report submitted by an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource with the monthly settlement

report for the Forward Capacity Market or Annual Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity 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.

**Metered Quantity For Settlement** is defined in Section III.3.2.1.1 of Market Rule 1.

**Minimum Consumption Limit** is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

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

**Minimum Generation Emergency** means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

**Minimum Generation Emergency Credits** are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

**Minimum Reduction** is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

**Minimum Reduction Time** is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

**Minimum Run Time** is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its

Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

**Minimum State of Charge** is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, below which the ISO shall not schedule the Electric Storage Facility to inject electricity to the grid.

**Minimum Time Between Reductions** is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

**Minimum Total Reserve Requirement**, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

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

**Monthly Capacity Payment** is the Capacity Market payment described in Section III.13.7.3 or Section III.15.8.3 of Market Rule 1.

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

**Monthly Qualified Capacity** is the amount of a resource's Qualified Capacity eligible to participate in a Monthly Reconfiguration Auction or Capacity Supply Obligation Bilateral during the applicable month.

**Monthly Real-Time Demand Reduction Obligation** is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

**Monthly Real-Time Generation Obligation** is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

**Monthly Real-Time Load Obligation** is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

**Monthly Reconfiguration Auction** is the reconfiguration auction conducted by the ISO each month as described in Section III.13.4.7 for those Monthly Reconfiguration Auctions held for months prior to the Capacity Commitment Period beginning on June 1, 2028 and in Section III.15.5 for those Monthly Reconfiguration Auctions held for months subsequent to the start of the Capacity Commitment Period beginning on June 1, 2028.

**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 ninth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

**MRI Transition Period** is the period specified in Section III.13.2.2.1.

**MUI** is the market user interface.

**Municipal Market Participant** is defined in Section II of the ISO New England Financial Assurance Policy.

**MW** is megawatt.

**MWh** is megawatt-hour.

**Native Load Customers** are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

**NCPC Charge** means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

**NCPC Credit** means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

**Needs Assessment** is defined in Section 4.1 of Attachment K to the OATT.

**NEMA**, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

**NEMA Contract** is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

**NEMA Load Serving Entity (NEMA LSE)** is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

**NEMA or Northeast Massachusetts Upgrade**, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

**NEPOOL** is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

**NEPOOL Agreement** is the agreement among the participants in NEPOOL.

**NEPOOL GIS** is the generation information system.

**NEPOOL GIS Administrator** is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

**NEPOOL GIS API Fees** are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that

accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

**NEPOOL Participant** is a party to the NEPOOL Agreement.

**NERC** is the North American Electric Reliability Corporation or its successor organization.

**NESCOE** is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

**Net Commitment Period Compensation (NCPC)** is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

**Net CONE** is an estimate of the Cost of New Entry, net of non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require to be economically viable given reasonable expectations of the energy and ancillary services revenues under long-term equilibrium conditions.

**Net Regional Clearing Price** is described in Section III.13.7.5 or Section III.15.8.5 of Market Rule 1.

**Net Supply** is energy injected into the transmission or distribution system at a Retail Delivery Point.

**Net Supply Capability** is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

**Network Capability Interconnection Standard** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Network Customer** is a Transmission Customer receiving RNS or LNS.

**Network Import Capability (NI Capability)** is defined in Section I of Schedule 25 of the OATT.

**Network Import Interconnection Service (NI Interconnection Service)** is defined in Section I of Schedule 25 of the OATT.

**Network Resource** is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired or deactivated; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired or deactivated, 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.

**Network Upgrades** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**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, New Demand Capacity Resource, or New Distributed Energy Capacity Resource.

**New Capacity Qualification Deadline** is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

**New Capacity Qualification Package** is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule

1.

**New Capacity Resource** is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

**New Capacity Show of Interest Form** is a form applicable to the Forward Capacity Market 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 applicable to the Forward Capacity Market during which a Project Sponsor may submit a New Capacity Show of Interest Form, a New Demand Capacity Resource Show of Interest Form, or a New Distributed Energy Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

**New Demand Capacity Resource** is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

**New Demand Capacity Resource Qualification Package** is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

**New Demand Capacity Resource Show of Interest Form** is a form applicable to the Forward Capacity Market described in Section III.13.1.4.1.1.1 of Market Rule 1.

**New Distributed Energy Capacity Resource** is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.1 of Market Rule 1.

**New Distributed Energy Capacity Resource Qualification Package** is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4A.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource.

**New Distributed Energy Capacity Resource Show of Interest Form** is a form applicable to the Forward Capacity Market described in Section III.13.1.4A.1.1.1 of Market Rule 1.

**NECEC Transmission LLC (NECEC)** is defined in Schedule 20B to Section II of this Tariff.

**New England Clean Energy Connect Transmission Line (NECEC Transmission Line)** is defined in Schedule 20B to Section II of this Tariff.

**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 Deactivation** is the permanent removal of a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource from all New England Markets, or the permanent reduction in Capacity Network Import Capability and Network Import Capability of an External Elective Transmission Upgrade, as described in Section II.I of the OATT.

**New England Markets** are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

**New England System Restoration Plan** is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

**New England Transmission System** is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

**New Generating Capacity Resource** is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

**New Import Capacity Resource** is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

**NMPTC** means Non-Market Participant Transmission Customer.

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

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

**Node** is a point on the New England Transmission System at which LMPs are calculated.

**No-Load Fee** is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

**Nominated Consumption Limit** is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.2.1 or Section III.15.8.5.2.1.

**Non-Commercial Capacity** is the capacity of a resource that cleared in a Forward Capacity Auction for periods prior to the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, or otherwise acquired a Capacity Supply Obligation and remains on Critical Path Schedule monitoring as of June 1, 2028, for some or all of its capacity that acquired a Capacity Supply Obligation.

**Non-Commercial Capacity Cure Period** is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

**Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount**) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity

Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

**Non-Designated Blackstart Resource Study Cost Payments** are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

**Non-Dispatchable Resource** is any Resource that does not meet the requirements to be a Dispatchable Resource.

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

**Non-Hourly Requirements** are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

**Non-Incumbent Transmission Developer** is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

**Non-Incumbent Transmission Developer Operating Agreement (or NTDOA)** is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

**Non-Market Participant** is any entity that is not a Market Participant.

**Non-Market Participant Transmission Customer** is any entity which is not a Market Participant but is a Transmission Customer.

**Non-Municipal Market Participant** is defined in Section II of the ISO New England Financial Assurance Policy.

**Non-PTF Transmission Facilities (Non-PTF)** are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

**Non-Qualifying** means a Market Participant that is not a Credit Qualifying Market Participant.

**Notice of RBA** is defined in Section 6.3.2 of the ISO New England Billing Policy.

**Notification Time** is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

**Northeastern Planning Protocol** is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

**NPCC** is the Northeast Power Coordinating Council.

**Obligation Month** means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

**Offer Data** means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

**Offered CLAIM10** is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

**Offered CLAIM30** is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

**On-Peak Demand Capacity Resource** is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

**Open Access Same-Time Information System (OASIS)** is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

**Open Access Transmission Tariff (OATT)** is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

**Operating Authority** is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

**Operating Data** means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

**Operating Day** means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

**Operating Reserve** means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

**Operations Date** is February 1, 2005.

**OTF Service** is transmission service over OTF as provided for in Schedule 20.

**Other Transmission Facility (OTF)** are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System.

**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 for the Phase I/II HVDC-TF and the NECEC Transmission Operating Agreement for the NECEC Transmission Line. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

**Other Transmission Owner (OTO)** is an owner of OTF.

**Ownership Share** is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

**Participant Expenses** are defined in Section 1 of the Participants Agreement.

**Participant Required Balance** is defined in Section 5.3 of the ISO New England Billing Policy.

**Participant Vote** is defined in Section 1 of the Participants Agreement.

**Participants Agreement** is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

**Participants Committee** is the principal committee referred to in the Participants Agreement.

**Participating Transmission Owner (PTO)** is a transmission owner that is a party to the TOA.

**Passive DR Audit** is the audit performed pursuant to Section III.13.6.1.5.4 or Section III.15.7.1.5.4.

**Passive DR Auditing Period** is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources.

**Payment** is a sum of money due to a Covered Entity from the ISO.

**Payment Default Shortfall Fund** is defined in Section 5.1 of the ISO New England Billing Policy.

**Permanent De-list Bid** is a bid submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

**Phase I Transfer Credit** is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

**Phase I/II HVDC-TF** is defined in Schedule 20A to Section II of this Tariff.

**Phase I/II HVDC-TF Transfer Capability** is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The "Phase II Transfer Capability" is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

**Phase One Proposal** is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

**Phase II Transfer Credit** is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

**Phase Two Solution** is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade by a Qualified Transmission Project Sponsor.

**Planning Advisory Committee** is the committee described in Attachment K of the OATT.

**Planning and Reliability Criteria** is defined in Section 3.3 of Attachment K to the OATT.

**Planning Authority** is an entity defined as such by the North American Electric Reliability Corporation.

**Point(s) of Delivery (POD)** is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

**Point of Interconnection** shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

**Point(s) of Receipt (POR)** is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

**Point-To-Point Service** is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

**Policy Scenario** is an Economic Study reference scenario that is described in Section 17.2(c) of Attachment K to the OATT.

**Pool-Planned Unit** is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

**Pool PTF Rate** is the transmission rate determined in accordance with Schedule 8 to the OATT.

**Pool RNS Rate** is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

**Pool-Scheduled Resources** are described in Section III.1.10.2 of Market Rule 1.

**Pool Supported PTF** is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

**Pool Transmission Facility (PTF)** means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

**Posting Entity** is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

**Posture** means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

**Posturing Credits** are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

**Power Purchaser** is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

**Principal** is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the

Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

**Profiled Load Assets** include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

**Project Sponsor** is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource, New Demand Capacity Resource, or New Distributed Energy Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

**Proposed Capacity Offer** is an offer submitted to the Internal Market Monitor for its review pursuant to Section III.A.22.2.3.

**Proportional Impact Method** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

**Proxy Capacity Offer** is a type of offer used in the Annual Capacity Market.

**Proxy De-List Bid** was a type of bid used in the Forward Capacity Market.

**Provisional Member** is defined in Section I.68A of the Restated NEPOOL Agreement.

**PTO Administrative Committee** is the committee referred to in Section 11.04 of the TOA.

**Public Policy Requirement** is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

**Public Policy Transmission Study** is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a

rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

**Public Policy Local Transmission Study** is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

**Public Policy Transmission Upgrade** is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

**Publicly Owned Entity** is defined in Section I of the Restated NEPOOL Agreement.

**Qualification Data Submission Deadline** is a date specified in the Capacity Auction Calendar by which a Lead Market Participant seeking to have a resource participate in the Annual Capacity Auction must submit qualification materials pursuant to Section III.15.2.1.1.

**Qualification Data Submission Package** is the package submitted to the ISO by a Lead Market Participant seeking to qualify a resource for the Annual Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral pursuant to Section III.15.2.1.1.

**Qualification Process Cost Reimbursement Deposit** is described in Section III.13.1.9.3 of Market Rule 1 and shall apply to all resources subject to Section III.15.A 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 prior to the 2028-2029 Capacity Commitment Period in the Forward Capacity Market qualification processes, or, for the 2028-2029 Capacity Commitment Period

and all Capacity Commitment Periods thereafter, through the Annual Capacity Market qualification and demonstration processes.

**Qualified Capacity Challenge and Restoration Plan Submission Window** is the period set forth in the Capacity Auction Calendar during which a Lead Market Participant may challenge the ISO-calculated summer and winter Qualified Capacity values of a Capacity Resource or submit a restoration plan to remedy a significant decrease in a Seasonal Qualified Capacity value of a Capacity Resource.

**Qualified Capacity Challenge and Restoration Plan Submission Deadline** is a date set forth in the Capacity Auction Calendar by which a Lead Market Participant may challenge the ISO-calculated summer and winter Qualified Capacity values of a Capacity Resource or submit a restoration plan to remedy a significant decrease in Qualified Capacity of a Capacity Resource..

**Qualified Generator Reactive Resource(s)** is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

**Qualified Non-Generator Reactive Resource(s)** is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

**Qualified Reactive Resource(s)** is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

**Qualified Transmission Project Sponsor** is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

**Queue Position** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Rapid Response Pricing Asset** is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

**Rapid Response Pricing Opportunity Cost** is the NCPC Credit described in Section III.F.2.3.10.

**Rated** means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

**Rating Agencies** are Standard and Poor's (S&P), Moody's, and Fitch.

**Rationing Minimum Limit** is the MW quantity below which a Capacity Offer may not be rationed in the Annual Capacity Auction.

**RBA Decision** is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

**Reactive Capability Audit** is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

**Reactive Resource** is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

**Reactive Supply and Voltage Control Service** is the form of Ancillary Service described in Schedule 2 of the OATT.

**Real-Time** is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

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

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

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

**Real-Time Congestion Revenue** is defined in Section III.3.2.1(i) of Market Rule 1.

**Real-Time Demand Reduction Obligation** is defined in Section III.3.2.1(c) of Market Rule 1.

**Real-Time Demand Reduction Obligation Deviation** is defined in Section III.3.2.1(e) of Market Rule 1.

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

**Real-Time Energy Inventory** is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

**Real-Time Energy Market** means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

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

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

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

**Real-Time Energy Market NCPC Credits** are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

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

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

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

**Real-Time High Operating Limit** is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 or Section III.15.7.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

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

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

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

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

**Real-Time Loss Revenue** is defined in Section III.3.2.1(l) of Market Rule 1.

**Real-Time Loss Revenue Charges or Credits** are defined in Section III.3.2.1(m) of Market Rule 1.

**Real-Time NCP Load Obligation** is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

**Real-Time Offer Change** is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

**Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Prices** means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

**Real-Time Reserve Charge** is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

**Real-Time Reserve Clearing Price** is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

**Real-Time Reserve Credit** is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

**Real-Time Reserve Designation** is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

**Real-Time Reserve Opportunity Cost** is defined in Section III.2.7A(b) of Market Rule 1.

**Real-Time SATOA Obligation** is defined in Section III.3.2.1(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.7 of Appendix A of Market Rule 1.

**Regional Benefit Upgrade(s) (RBU)** means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a System 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). 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. A Network Customer's Monthly Regional Network Load shall be calculated in accordance with Section II.21.2 of the OATT.

**Regional Network Service (RNS)** is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

**Regional Planning Dispute Resolution Process** is described in Section 12 of Attachment K to the OATT.

**Regional System Plan (RSP)** is the plan developed under the process specified in Attachment K of the OATT.

**Regional Transmission Service (RTS)** is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

**Regulation** is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

**Regulation and Frequency Response Service** is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

**Regulation Capacity** is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

**Regulation Capacity Requirement** is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

**Regulation Capacity Offer** is an offer by a Market Participant to provide Regulation Capacity.

**Regulation High Limit** is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

**Regulation Low Limit** is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

**Regulation Market** is the market described in Section III.14 of Market Rule 1.

**Regulation Resources** are those Alternative Technology Regulation Resources and Generator Assets that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

**Regulation Service** is the change in output or consumption made in response to changing AGC SetPoints.

**Regulation Service Requirement** is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

**Regulation Service Offer** is an offer by a Market Participant to provide Regulation Service.

**Related Person** is defined pursuant to Section 1.1 of the Participants Agreement.

**Related Transaction** is defined in Section III.1.4.3 of Market Rule 1.

**Reliability Administration Service (RAS)** is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

**Reliability Committee** is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

**Reliability Markets** are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, the Annual 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 system efficiency benefits as well as reliability benefits to the New England Transmission System.

**Remittance Advice** is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

**Remittance Advice Date** is the day on which the ISO issues a Remittance Advice.

**Renewable Technology Resource** is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

**Re-Offer Period** is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

**Replacement Reserve** is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

**Request for Alternative Proposals (RFAP)** is the request described in Attachment K of the OATT.

**Requested Billing Adjustment (RBA)** is defined in Section 6.1 of the ISO New England Billing Policy.

**Required Balance** is an amount as defined in Section 5.3 of the Billing Policy.

**Reseller** is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

**Reserve Adequacy Analysis** is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

**Reserve Constraint Penalty Factors (RCPFs)** are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1, and that are used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of Day-Ahead Flexible Response Services shortages and defined in Section III.2.6.2(c) of Market Rule 1.

**Reserve Quantity For Settlement** is defined in Section III.10.1 of Market Rule 1.

**Reserve Zone** is defined in Section III.2.7 of Market Rule 1.

**Reserved Capacity** is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

**Resource** means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, a Demand Response Resource, a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation.

**Resource Adequacy Assessment Qualified Capacity** is the amount of summer and winter Qualified Capacity determined pursuant to Section III.15.3 of Market Rule 1 for all Capacity Resources identified in Section III.12.7.2(a) of Market Rule 1, at the start of the Resource Adequacy Assessment process that begins in June of the year preceding the relevant Capacity Commitment Period.

**Restated New England Power Pool Agreement (RNA)** is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

**Rest-of-Pool Capacity Zone** is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

**Rest of System** is an area established under Section III.2.7(d) of Market Rule 1.

**Retail Delivery Point** is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

**Retirement De-List Bid** is a bid in the Forward Capacity Market to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

**Returning Market Participant** is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

**Revenue Requirement** is defined in Section IV.A.2.1 of the Tariff.

**Reviewable Action** is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

**Reviewable Determination** is defined in Section 12.4(a) of Attachment K to the OATT.

**Round-Trip Efficiency** is a percentage expressing the megawatt-hours of energy that an Electric Storage Facility injects onto the grid per megawatt-hour of energy it receives from the grid.

**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.

**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 20 Service Provider (SSP)** references Schedule 20A Service Providers and/or Schedule 20B Service Provider.

**Schedule 20A Service Provider** is defined in Schedule 20A to Section II of this Tariff.

**Schedule 20B Service Provider** refers to NECEC as defined in Schedule 20B to Section II of this Tariff.

**Scheduling Service**, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

**Scheduling, System Control and Dispatch Service**, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

**Seasonal Claimed Capability** is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

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

**Seasonal DR Audit** is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

**Seasonal Peak Demand Capacity Resource** is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

**Seasonal Qualified Capacity Notification Date** is a date described in the Capacity Auction Calendar by which the ISO shall notify Market Participants of their Seasonal Qualified Capacity for the upcoming Capacity Commitment Period.

**Seasonal Qualified Capacity Values** are the summer and winter Qualified Capacity calculated by the ISO pursuant to Section 15.2.7.

**Section III.1.4 Transactions** are defined in Section III.1.4.2 of Market Rule 1.

**Section III.1.4 Conforming Transactions** are defined in Section III.1.4.2 of Market Rule 1.

**Security Agreement** is Attachment 1 to the ISO New England Financial Assurance Policy.

**Selected Qualified Transmission Project Sponsor** is the Qualified Transmission Project Sponsor that proposed the Phase Two Solution, Stage Two Solution, Longer-Term Proposal, or System Efficiency Transmission Upgrade Proposal that has been identified by the ISO as the preferred Phase Two Solution, Stage Two Solution, Longer-Term Transmission Solution, or System Efficiency Transmission Upgrade Solution.

**Selected Qualified Transmission Project Sponsor Agreement** is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

**Self-Schedule** is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to

provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction in the Day-Ahead Energy Market, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction subject to the conditions specified in Section III.1.10.1A(b)(iii) and (iv). For an External Transaction in the Real-Time Energy Market, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of LMP. Demand Response Resources are not permitted to Self-Schedule.

**Self-Supplied FCA Resource** is described in Section III.13.1.6 of Market Rule 1.

**Self-Supplied Capacity Resource** is described in Section III.15.2.9.1 of Market Rule 1.

**Senior Officer** means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that officer.

**Service Agreement** is a Transmission Service Agreement or an MPSA.

**Service Commencement Date** is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

**Services** means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

**Settlement Financial Assurance** is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

**Settlement Only Distributed Energy Resource Aggregation (SODERA)** is a type of Distributed Energy Resource Aggregation and is described in additional detail in Section III.6.6.

**Settlement Only Resources** are generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

**Shortfall Funding Arrangement**, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

**Short-Term** is a period of less than one year.

**Significantly Reduced Congestion Costs** are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

**SMD Effective Date** is March 1, 2003.

**Solar High Limit** is the estimated power output (MW) of a solar Generator Asset given the Real-Time solar and weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

**Solar Plant Future Availability** is the forecasted Real-Time High Operating Limit of a solar Generator Asset, calculated in the manner described in the ISO Operating Documents.

**Solutions Study** is described in Section 4.2(b) of Attachment K to the OATT.

**Special Constraint Resource (SCR)** is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

**Special Constraint Resource Service** is the form of Ancillary Service described in Schedule 19 of the OATT.

**Specified-Term Blackstart Capital Payment** is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

**Sponsored Policy Resource** is a resource, each asset of which: receives a revenue source, other than revenues from ISO-administered markets, that is supported by a government-regulated rate, charge, or other regulated cost recovery mechanism, and; qualifies as a renewable, clean, zero carbon, or alternative energy asset under a renewable energy portfolio standard, clean energy standard, decarbonization or net-zero carbon standard, alternative energy portfolio standard, renewable energy goal, clean energy goal, or decarbonization or net-zero carbon goal enacted by federal or New England state statute, regulation, or executive or administrative order and as a result of which the asset receives the revenue source.

**Stage One Proposal** is a first round submission, as defined in Section 4A.6 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.8 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

**Stakeholder-Requested Scenario** is an Economic Study reference scenario that is described in Section 17.2(d) of Attachment K to the OATT.

**Standard Blackstart Capital Payment** is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

**Start-of-Round Price** is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

**Start-Up Fee** is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

**Start-Up Time** is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

**State Estimator** means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

**State of Charge** is the total quantity of megawatt-hours available to be injected by an Electric Storage Facility onto the grid.

**State-identified Requirement** refers to a legal requirement, mandate or policy of a New England state or local government that forms the basis for a Longer-Term Transmission Study request submitted to the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT.

**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 submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

**Station** is one or more Generating Capacity Resources consisting of one or more assets located within a common property boundary.

**Station Going Forward Common Costs** are the net costs associated with a Station that are avoided only if none of the Generating Capacity Resources composing the Station acquire a Capacity Supply Obligation for the Capacity Commitment Period, or by deactivating all Generating Capacity Resources composing the Station.

**Station-level Blackstart O&M Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Station-level Specified-Term Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Storage as Transmission-Only Asset (SATOA)** is electric storage equipment that: (1) is connected to or to be connected to Pool Transmission Facilities in the New England Transmission System at a voltage level of 115 kV or higher; (2) the ISO approved to be included in the Regional System Plan and RSP Project List as a regulated transmission solution and Pool Transmission Facility pursuant to the regional system planning processes in Attachment K of the OATT; and (3) is capable of receiving energy only from the Pool Transmission Facilities and storing the energy for later injection to the Pool Transmission Facilities.

**Station-level Standard Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Storage DARD** is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Substation Network Upgrades** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**Summer ARA Qualified Capacity** is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

**Summer Capability Period** means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

**Summer Intermittent Reliability Hours** are defined in Section III.13.1.2.2.2.1(c) or Section III.15.3.2.1(b) 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 Efficiency Needs Assessment** is defined in Section 17.9 of Attachment K to the OATT.

**System Efficiency Needs Scenario** is an Economic Study reference scenario that is described in Section 17.2(b) of Attachment K to the OATT.

**System 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 financial benefits they provide exceed the cost of the transmission addition or upgrade.

**System Efficiency Transmission Upgrade Proposal** is a proposal submitted by a Qualified Transmission Project Sponsor pursuant to Section 17.12 of Attachment K to the OATT

**System Efficiency Transmission Upgrade Solution** is the System Efficiency Transmission Upgrade Proposal identified as the preferred solution pursuant to Section 17.12 of Attachment K to the OATT.

**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 Network Upgrades** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**System Operator** shall mean ISO New England Inc. or a successor organization.

**System Operating Limit (SOL)** has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

**System-Wide Capacity Demand Curve** is the demand curve used in the Capacity Market as specified in Section III.13.2.2 or Section III.15.1.1.1.

**TADO** is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

**Tangible Net Worth** is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net

of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

**Technical Committee** is defined in Section 8.2 of the Participants Agreement.

**Ten-Minute Non-Spinning Reserve (TMNSR)** is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

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

**Ten-Minute Reserve Requirement** is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**Ten-Minute Spinning Reserve (TMSR)** is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

**Ten-Minute Spinning Reserve Requirement** is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**Ten-Minute Spinning Reserve Service** is the form of Ancillary Service described in Schedule 5 of the OATT.

**Third-Party Sale** is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

**Thirty-Minute Operating Reserve (TMOR)** is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

**Thirty-Minute Operating Reserve Service** is the form of Ancillary Service described in Schedule 7 of the OATT.

**Through or Out Rate (TOUT Rate)** is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

**Through or Out Service (TOUT Service)** means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

**Tie-Line Asset** is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

**Total Available Amount** is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

**Total Blackstart Capital Payment** is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

**Total Blackstart Service Payments** is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

**Total Reserve Requirement**, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**Total System Capacity** is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

**Transaction Unit (TU)** is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

**Transition Period**: The six-year period commencing on March 1, 1997.

**Transmission Charges**, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

**Transmission Congestion Credit** means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

**Transmission Congestion Revenue** is defined in Section III.5.2.5(a) of Market Rule 1.

**Transmission Constraint Penalty Factors** are described in Section III.1.7.5 of Market Rule 1.

**Transmission Credit Limit** is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

**Transmission Credit Test Percentage** is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

**Transmission Customer** is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20 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 20 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; the Schedule 20B Service Provider for NECEC Transmission Line Transmission Service as provided under Schedule 20B 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 20 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.

**Transitional Cluster Study** has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

**Transitional CNR Group Study** has the meaning specified in Section I of Schedule 22, Section I of 23, and Section I of 25 of the OATT.

**UDS** is unit dispatch system software.

**Unconstrained Export Transaction** is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

**Uncovered Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Uncovered Transmission Default Amounts** are defined in Section 3.4.f of the ISO New England Billing Policy.

**Unrated** means a Market Participant that is not a Rated Market Participant.

**Unsecured Covered Entity** is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

**Unsecured Municipal Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Unsecured Municipal Market Participant** is defined in Section 3.3(h) of the ISO New England Billing Policy.

**Unsecured Municipal Transmission Default Amount** is defined in Section 3.4.f of the ISO New England Billing Policy.

**Unsecured Non-Municipal Covered Entity** is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

**Unsecured Non-Municipal Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Unsecured Non-Municipal Transmission Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Unsecured Transmission Default Amounts** are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

**Unsettled FTR Financial Assurance** is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

**Updated Measurement and Verification Plan** is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1, and the ISO New England Manuals.

**VAR CC Rate** is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

**VAR Payment** is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

**VAR Service** is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

**Virtual Cap** is $2,000/MWh.

**Virtual Requirements** are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

**Volt Ampere Reactive (VAR)** is a measurement of reactive power.

**Volumetric Measure (VM)** is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

**Wind High Limit** is the estimated power output (MW) of a wind Generator Asset given the Real-Time weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

**Wind Plant Future Availability** is the forecasted Real-Time High Operating Limit of a wind Generator Asset, calculated in the manner described in the ISO Operating Documents.

**Winter ARA Qualified Capacity** is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

**Winter Capability Period** means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

**Winter Intermittent Reliability Hours** are defined in Section III.13.1.2.2.2.2(c) or Section III.15.3.2.2(b) of Market Rule 1.

**Year** means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

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

**Zonal Capacity Obligation** is calculated in accordance with Section III.13.7.5.2 and Section III.15.8.5.2 of Market Rule 1.

**Zonal Reserve Requirement** is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**EXHIBIT IA**

**ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY**

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**EXHIBIT IA**

**ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY**

**Overview**

The procedures and requirements set forth in this ISO New England Financial Assurance Policy shall govern all Applicants, all Market Participants and all Non-Market Participant Transmission Customers. Capitalized terms used in the ISO New England Financial Assurance Policy shall have the meaning specified in Section I.

The purpose of the ISO New England Financial Assurance Policy is (i) to establish minimum criteria for participation in the New England Markets; (ii) to establish a financial assurance policy for Market Participants and Non-Market Participant Transmission Customers that includes commercially reasonable credit review procedures to assess the financial ability of an Applicant, a Market Participant or a Non-Market Participant Transmission Customer to pay for service transactions under the Tariff and to pay its share of the ISO expenses, including amounts under Section IV of the Tariff, and including any applicable Participant Expenses; (iii) to set forth the requirements for alternative forms of security that will be deemed acceptable to the ISO and consistent with commercial practices established by the Uniform Commercial Code that protect the ISO and the Market Participants against the risk of non-payment by other, defaulting Market Participants or by Non-Market Participant Transmission Customers; (iv) to set forth the conditions under which the ISO will conduct business in a nondiscriminatory way so as to avoid the possibility of failure of payment for services rendered under the Tariff; and (v) to collect amounts past due, to collect amounts payable upon billing adjustments, to make up shortfalls in payments, to suspend Market Participants and Non-Market Participant Transmission Customers that fail to comply with the terms of the ISO New England Financial Assurance Policy, to terminate the membership of defaulting Market Participants and to terminate service to defaulting Non-Market Participant Transmission Customers.

## I. GROUPS REGARDED AS SINGLE MARKET PARTICIPANTS

In the case of a group of Entities that are treated as a single Market Participant pursuant to Section 4.1 of the Second Restated NEPOOL Agreement (the "RNA"), the group members shall be deemed to have elected to be jointly and severally liable for all debts to Market Participants, PTOs, Non-Market Participant Transmission Customers, NEPOOL and the ISO of any of the group members. For the purposes of the ISO New England Financial Assurance Policy, the term "Market Participant" shall, in the case of a group of members that are treated as a single Market Participant pursuant to Section 4.1 of the RNA, be deemed to refer to the group of members as a whole, and any financial assurance provided

under the ISO New England Financial Assurance Policy will be credited to the account of the group member with the customer identification at the ISO.

## II. MARKET PARTICIPANTS' REVIEW AND CREDIT LIMITS

Solely for purposes of the ISO New England Financial Assurance Policy: a "Municipal Market Participant" is any Market Participant that is either (a) a Publicly Owned Entity except for an electric cooperative or an organization including one or more electric cooperatives as used in Section 1 of the RNA or (b) a municipality, an agency thereof, a body politic or a public corporation (i) that is created under the authority of any state or province that is adjacent to one of the New England states, (ii) that is authorized to own, lease and operate electric generation, transmission or distribution facilities and (iii) that has been approved for treatment as a Municipal Market Participant by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee. Market Participants that are not Municipal Market Participants are referred to as "Non-Municipal Market Participants."

### A. Minimum Criteria for Market Participation

Any entity participating or seeking to participate in the New England Markets shall comply with the requirements of this Section II.A. For purposes of this Section II.A, the term "customer" shall refer to both Market Participants and Non-Market Participant Transmission Customers and the word "applicant" shall refer to both applicants for Market Participant status and applicants for transmission service from the ISO.

#### 1. Information Disclosure

(a) Each customer and applicant, on an annual basis (by April 30 each year) shall submit a completed information form in the form of (with only minor, non-material changes) and with the information required by Attachment 6 to the ISO New England Financial Assurance Policy. Customer or applicant shall not be required to disclose information required by Attachment 6 if such disclosure is prohibited by law; provided, however, if the disclosure of any information required by Attachment 6 is prohibited by law, then customer or applicant shall use reasonable efforts to obtain permission to make such disclosure. This information shall be treated as Confidential Information, but its disclosure pursuant to subsection (b) below is expressly permitted in accordance with the terms of the ISO New England Information Policy. Customers and applicants may satisfy the requirements above by providing the ISO with filings made to the Securities

and Exchange Commission or other similar regulatory agencies that include substantially similar information to that required above, provided, however, that the customer or applicant must clearly indicate where the specific information is located in those filings. An applicant that fails to provide this information will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this information by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the information to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) The ISO will review the information provided pursuant to subsection (a) above, and will also review whether the customer or applicant or any of the Principals of the customer or applicant are included on any relevant list maintained by the U.S. Office of Foreign Asset Control. If, after review of the information provided pursuant to subsection (a) above or any other information disclosed pursuant to this Section II, the ISO in its sole discretion requires additional information to make its analysis under this subsection (b), the ISO may require additional information from the customer or applicant. If, based on these reviews, the ISO determines that the commencement or continued participation of such customer or applicant in the New England Markets may present an unreasonable risk to those markets or its Market Participants, the Chief Financial Officer of the ISO shall promptly forward to the Participants Committee or its delegate, for its input, such concerns, together with such background materials deemed by the ISO to be necessary for the Participants Committee or its delegate to develop an informed opinion with respect to the identified concerns, including any measures that the ISO may recommend imposing as a condition to the commencement or continued participation in the markets by such customer or applicant (including suspension) or the ISO's recommendation to prohibit or terminate participation by the customer or applicant in the New England Markets. The ISO shall consider the input of the Participants Committee or its delegate before taking any action to address the identified concerns. If the ISO chooses to impose measures other than prohibition (in the case of an applicant) or termination (in the case of a customer) of participation in the New England Markets, then the ISO shall be required to make an informational filing with the Commission as soon as reasonably practicable after taking such action. If the ISO chooses to prohibit (in the case of an applicant) or

terminate (in the case of a customer) participation in the New England Markets, then the ISO must file for Commission approval of such action, and the prohibition or termination shall become effective only upon final Commission ruling. No action by the ISO pursuant to this subsection (b) shall limit in any way the ISO's rights or authority under any other provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy.

**2. Risk Management**

(a) Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has: (i) either established or contracted for risk management procedures that are applicable to participation in the New England Markets; and (ii) has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) Each applicant prior to commencing activity in the FTR market shall submit to the ISO or its designee the written risk management policies, procedures, and controls, including, if requested by the ISO in its sole discretion, supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, applicable to its participation in the FTR market relied upon by the Senior Officer of the applicant signing the certificate provided pursuant to Section II.A.2 (a). On an annual basis (by April 30 each year), each Designated FTR Participant with FTR transactions in any of the previous twelve months or in any currently open month

that exceed 1,000 MW per month (on a net basis, as described in the FTR Financial Assurance Requirements provisions in Section VI) shall submit to the ISO or its designee a certificate in the form of Attachment 5 to the ISO New England Financial Assurance Policy stating that, since the customer's delivery of its risk management policies, procedures, and controls (and any supporting documentation, if applicable) or its last certificate pursuant to this Section II.A.2(b), the customer either: (i) has not made any changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable); or (ii) that changes have been made to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) and that all such changes are clearly identified and attached to such certificate. If any such applicant fails to submit the relevant written policies, procedures, and controls, then the applicant will be prohibited from participating in the FTR market. If any such customer fails to provide a certificate in the form of Attachment 5 by end of business on April 30, then the ISO shall issue a notice of such failure to the customer, and if the customer does not provide the certificate to the ISO within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions in the FTR system.

The ISO, at its sole discretion, may also require any applicant or customer to submit to the ISO or its designee the written risk management policies, procedures, and controls, including supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, that are applicable to its participation in the New England Markets relied upon by the Senior Officer of the applicant or customer signing the certificate provided pursuant to Section II.A.2(a). The ISO may require such submissions based on identified risk factors that include, but are not limited to, the markets in which the customer is transacting or the applicant seeks to transact, the magnitude of the customer's transactions or the applicant's potential transactions, or the volume of the customer's open positions. Where the ISO notifies an applicant or customer that such a submission is required, the submission shall be due within 5 Business Days of the notice. If an applicant fails to submit the relevant written policies, procedures, and controls as required, then the applicant will be prohibited from participating in the New England Markets. If a

customer fails to submit the relevant written policies, procedures, and controls, then the ISO shall issue a notice of such failure to the customer, and if the customer fails to submit the relevant written policies, procedures, and controls to the ISO or its designee within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

The applicant's or customer's written policies, procedures, controls, and any supporting documentation, received by the ISO or its designee pursuant to this subsection (b) shall be treated as Confidential Information.

(c) Where an applicant or customer submits risk management policies, procedures, and controls, or supporting documentation to the ISO or its designee pursuant to any provision of subsection (b) above, the ISO or its designee shall assess that those policies, procedures, and controls conform to prudent risk management practices, which include, but are not limited to: (i) addressing market, credit, and operational risk; (ii) segregating roles, responsibilities, and functions in the organization; (iii) establishing delegations of authority that specify which transactions traders are authorized to enter into; (iv) ensuring that traders have sufficient training in systems and the markets in which they transact; (v) placing risk limits to control exposure; (vi) requiring reports to ensure that risks are adequately communicated throughout the organization; (vii) establishing processes for independent confirmation of executed transactions; and (viii) establishing periodic valuation or mark-to-market of risk positions as appropriate.

Where, as a result of the assessment described above in this subsection (c), the ISO or its designee believes that the applicant's or customer's written policies, procedures, and controls do not conform to prudent risk management practices, then the ISO or its designee shall provide notice to the applicant or customer explaining the deficiencies. The applicant or customer shall revise its policies, procedures, and controls to address the deficiencies within 55 days after issuance of such notice. (If April 30 falls within that 55 day window, the ISO may choose not to require a separate submission on April 30 as described in subsection (b) above.) If an applicant's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the applicant will be prohibited from participating in the New England Markets. If a customer's revised written policies, procedures, and controls do not adequately address

the deficiencies identified in the notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

**3. Communications**

Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has either established or contracted to establish procedures to effectively communicate with and respond to the ISO with respect to matters relating to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy. Such procedures must ensure, at a minimum, that at least one person with the ability and authority to address matters related to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy on behalf of the customer or applicant, including the ability and authority to respond to requests for information and to arrange for additional financial assurance as necessary, is available from 9:00 a.m. to 5:00 p.m. Eastern Time on Business Days. Such procedures must also ensure that the ISO is kept informed about the current contact information (including phone numbers and e-mail addresses) for the person or people described above. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

**4. Capitalization**

(a) To be deemed as meeting the capitalization requirements, a customer or applicant shall either:

(i) be Rated and have a Governing Rating that is an Investment Grade Rating of BBB-/Baa3 or higher;

(ii) maintain a minimum Tangible Net Worth of one million dollars; or

(iii) maintain a minimum of ten million dollars in total assets, provided that, to meet this requirement, a customer or applicant may supplement total assets of less than ten million dollars with additional financial assurance in an amount equal to the difference between ten million dollars and the customer's or applicant's total assets in one of the forms described in Section X (any additional financial assurance provided pursuant to this Section II.A.4(a) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy).

(b) Any customer or applicant that fails to meet these capitalization requirements will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions of a duration greater than one month in the FTR system or any future transactions for a duration of one month or less except when FTRs for a month are being auctioned for the final time. Such a customer or applicant may enter into future transaction of a duration of one month or less in the FTR system in the case of FTRs for a month being auctioned for the final time. Any customer or applicant that fails to meet these capitalization requirements shall provide additional financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy equal to 25 percent of the customer's or applicant's FTR Financial Assurance Requirements. Any additional financial assurance provided pursuant to this Section II.A.4(b) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

(c) For markets other than the FTR market:

(i) Where a customer or applicant fails to meet the capitalization requirements, the customer or applicant will be required to provide an additional amount of financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy in an amount equal to 25 percent of the customer's or applicant's total financial assurance requirement, excluding the following:

- FTR Financial Assurance Requirements; and
- FCM Delivery Financial Assurance for customers or applicants that are assessed as medium risk or high risk per the Corporate Liquidity

Assessment (as described in Section VII.A below) from the start of the Capacity Commitment Period related to the sixteenth Forward Capacity Auction (i.e., June 1, 2025) or any Capacity Commitment Period thereafter.

(ii) An applicant that fails to provide the full amount of additional financial assurance required as described in subsection (i) above will be prohibited from participating in the New England Markets until the deficiency is rectified. For a customer, failure to provide the full amount of additional financial assurance required as described in subsection (i) above will have the same effect and will trigger the same consequences as exceeding the "100 Percent Test" as described in Section III.B.2.c of the ISO New England Financial Assurance Policy.

(iii) Any additional financial assurance provided pursuant to this Section II.A.4(c) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

**5. Additional Eligibility Requirements**

All customers and applicants shall at all times be:

(a) An "appropriate person," as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 1 *et seq.*);
(b) An "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or
(c) A "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

Each customer must demonstrate compliance with the requirements of this Section II.A.5 by submitting to the ISO on or before September 15, 2013 a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the customer is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately

cease all participation in the New England Markets. If the customer is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the customer's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the customer by a Senior Officer of the customer. A customer that fails to provide this certificate by September 15, 2013 shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

Each applicant must submit with its membership application a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the applicant is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately cease all participation in the New England Markets. If the applicant is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the applicant's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the applicant by a Senior Officer of the applicant.

The ISO, at its sole discretion, may require any applicant or customer to submit to the ISO documentation in support of the certification provided pursuant to this Section II.A.5. If at any time the ISO becomes aware that a customer no longer satisfies the requirements of this Section II.A.5, the customer shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

**6. Prior Uncured Defaults**

In addition to, and not in limitation of Section IV of the ISO New England Financial Assurance Policy, an applicant who has a previous uncured payment default must cure such payment default by payment to the ISO of all outstanding and unpaid obligations, as well as meet all requirements for participation in the New England Markets contained in the ISO New England Financial Assurance Policy. For purposes of this Section II.A.6 and the ISO's evaluation of information disclosed pursuant to Section II of the ISO New England Financial Assurance Policy, the ISO will evaluate relevant factors to determine if an entity seeking to participate in the New England Markets under a different name, affiliation, or organization, should be treated as the same customer or applicant that experienced the previous payment default. Such factors may include, but are not limited to, the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base, and the business engaged in prior to the attempted re-entry. Notwithstanding the foregoing, an applicant shall not be required to cure a payment default that has lawfully been discharged pursuant to the U.S. Bankruptcy Code.

**B. Proof of Financial Viability for Applicants**

Each Applicant must, with its membership application and at its own expense, submit proof of financial viability, as described below, satisfying the ISO requirements to demonstrate the Applicant's ability to meet its obligations. Each Applicant that intends to establish a Market Credit Limit or a Transmission Credit Limit of greater than $0 under Section II.D or Section II.E below must submit to the ISO all current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch (collectively, the "Rating Agencies"). Each Applicant, whether or not it intends to establish a Market Credit Limit or Transmission Credit Limit of greater than $0, must submit to the ISO audited financial statements for the two most recent years, or the period of its existence, if less than two years, and unaudited financial statements for its last concluded fiscal quarter if they are not included in such audited annual financial statements. These unaudited statements must be certified as to their accuracy by a Senior Officer of such Applicant, which, for purposes of ISO New England Financial Assurance Policy, means an officer of the subject entity with the title of vice president (or similar office) or higher,

or another officer designated in writing to the ISO by that officer. These audited and unaudited statements must include in each case, but are not limited to, the following information to the extent available: balance sheets, income statements, statements of cash flows and notes to financial statements, annual and quarterly reports, and 10-K, 10-Q and 8-K Reports. If any of these financial statements are available on the internet, the Applicant may provide instead a letter to the ISO stating where such statement may be located and retrieved. If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO, at the ISO's sole discretion (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; or (iii) compiled statements).

In addition, each Applicant, whether or not it intends to establish a Market Credit Limit or a Transmission Credit Limit, must submit to the ISO: (i) at least one (1) bank reference and three (3) utility company credit references, or in those cases where an Applicant does not have three (3) utility company credit references, three (3) major trade payable vendor references may be substituted; and (ii) relevant information as to any known or anticipated material lawsuits, as well as any prior bankruptcy declarations by the Applicant, or by its predecessor(s), if any; and (iii) a completed ISO credit application. In the case of certain Applicants, some of the information and documentation described in items (i) and (ii) of the immediately preceding sentence may not be applicable or available, and alternate requirements may be specified by the ISO or its designee in its sole discretion.

The ISO will not begin its review of a Market Participant's credit application or the accompanying material described above until full and final payment of that Market Participant's application fee.

The ISO shall prepare a report, or cause a report to be prepared, concerning the financial viability of each Applicant. In its review of each Applicant, the ISO or its designee shall consider all of the information and documentation described in this Section II. All costs

incurred by the ISO in its review of the financial viability of an Applicant shall be borne by such Applicant and paid at the time that such Applicant is required to pay its first annual fee under the Participants Agreement. For an Applicant applying for transmission service from the ISO, all costs incurred by the ISO shall be paid prior to the ISO's filing of a Transmission Service Agreement. The report shall be provided to the Participants Committee or its designee and the affected Applicant within three weeks of the ISO's receipt of that Applicant's completed application, application fee, and Initial Market Participant Financial Assurance Requirement, unless the ISO notifies the Applicant that more time is needed to perform additional due diligence with respect to its application.

## C. Ongoing Review and Credit Ratings

### 1. Rated and Credit Qualifying Market Participants

A Market Participant that (i) has a corporate rating from one or more of the Rating Agencies, or (ii) has senior unsecured debt that is rated by one or more of the Rating Agencies, is referred to herein as "Rated." A Market Participant that is not Rated is referred to herein as "Unrated."

For all purposes in the ISO New England Financial Assurance Policy, for a Market Participant that is Rated, 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, shall be the "Governing Rating."

A Market Participant that is: (i) Rated and whose Governing Rating is an Investment Grade Rating; or (ii) Unrated and that satisfies the Credit Threshold is referred to herein as "Credit Qualifying." A Market Participant that is not Credit Qualifying is referred to herein as "Non-Qualifying."

For purposes of the ISO New England Financial Assurance Policy, "Investment Grade Rating" for a Market Participant (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.

**2. Unrated Market Participants**

Any Unrated Market Participant that (i) has not been a Market Participant in the ISO for at least the immediately preceding 365 days; or (ii) has defaulted on any of its obligations under the Tariff (including without limitation its obligations hereunder and under the ISO New England Billing Policy) during such 365-day period; or (iii) is an FTR-Only Customer; or (iv) does not have a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 must provide an appropriate form of financial assurance as described in Section X below. An Unrated Market Participant that does not meet any of the conditions in clauses (i), (ii), (iii) and (iv) of this paragraph is referred to herein as satisfying the "Credit Threshold."

For purposes of the ISO New England Financial Assurance Policy, "Current Ratio" on any date is 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; "Debt-to-Total Capitalization Ratio" on any date is 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; and "EBITDA-to-Interest Expense Ratio" on any date is 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. The "Debt-to-Total Capitalization Ratio" will not be considered for purposes of determining whether a Municipal Market Participant satisfies the Credit Threshold. Each of the ratios described in this paragraph shall be determined in accordance with international

accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied.

**3. Information Reporting Requirements for Market Participants**

Each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis within 10 days of its becoming available and within 65 days after the end of the applicable fiscal quarter of such Market Participant, its balance sheet, which shall show sufficient detail for the ISO to assess the Market Participant's Tangible Net Worth. Unrated Market Participants having a Market Credit Limit or Transmission Credit Limit greater than zero shall also provide additional financial statements, which shall show sufficient detail for the ISO to calculate such Unrated Market Participant's Current Ratio, Debt-to-Total Capitalization Ratio and EBITDA-to-Interest Expense Ratio. In addition, each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of their becoming available and within 120 days after the end of the fiscal year of such Market Participant, balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). If any of this financial information is available on the internet, the Market Participant may provide instead a letter to the ISO stating where such information may be located and retrieved. If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; (iii) compiled statements; (iv) internally prepared statements; or (v) tax returns).

Except in the case of a Market Participant or Unrated Market Participant that submits audited financial statements to the ISO, financial statements submitted to the ISO pursuant to this Section II.C.3 shall be accompanied by a written statement from a Senior Officer of the Market Participant or Unrated Market Participant certifying the accuracy of those financial statements. If an attestation was made by an independent accounting firm, then the written statement shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required.

Notwithstanding any other provision in this subsection, the ISO may require any Market Participant to submit the financial statements and other information described in this subsection. The Market Participant shall provide the requested statements and other information within 10 days of such request. If a Market Participant fails to provide financial statements or other information as requested and the ISO determines that the Market Participant poses an unreasonable risk to the New England Markets, then the ISO may request that the Market Participant provide additional financial assurance in an amount no greater than $10 million, or take other measures to substantiate the Market Participant's ability to safely transact in the New England Markets (any additional financial assurance provided pursuant to this Section II.C.3 shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy). If the Market Participant fails to comply with such a request from the ISO, then the ISO may issue a notice of suspension or termination to the Market Participant. If the Market Participant fails to comply with the ISO's request within 5 Business Days from the date of issuance of the notice of suspension or termination, then the ISO may suspend or terminate the Market Participant.

A Market Participant may choose not to submit financial statements as described in this Section II.C.3, in which case the ISO shall use a value of $0.00 for the Market Participant's total assets and Tangible Net Worth for purposes of the capitalization assessment described in Section II.A.4(a) and such Market Participant's Market Credit Limit and Transmission Credit Limit shall be $0.00.

A Market Participant may choose to provide additional financial assurance in an amount equal to $10 million in lieu of providing financial statements under this Section II.C.3.

Such amount shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy but shall be sufficient to meet the capitalization requirements in Section II.A.4(a)(iii).

**D. Market Credit Limits**

A credit limit for a Market Participant's Financial Assurance Obligations except FTR Financial Assurance Requirements (a "Market Credit Limit") shall be established for each Market Participant in accordance with this Section II.D.

**1. Market Credit Limit for Non-Municipal Market Participants**

A "Market Credit Limit" shall be established for each Rated Non-Municipal Market Participant in accordance with subsection (a) below, and a Market Credit Limit shall be established for each Unrated Non-Municipal Market Participant in accordance with subsection (b) below.

**a. Market Credit Limit for Rated Non-Municipal Market Participants**

As reflected in the following table, the Market Credit Limit of each Rated Non-Municipal Market Participant (other than an FTR-Only Customer) shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table, (ii) $50 million, or (iii) 20 percent (20%) of 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 ("TADO").

| **Investment Grade Rating** | | **Percentage of Tangible Net Worth** |
|---|---|---|
| **S&P/Fitch** | **Moody's** | |
| AAA | Aaa | 5.50% |
| AA+ | Aa1 | 5.50% |
| AA | Aa2 | 4.50% |
| AA- | Aa3 | 4.00% |
| A+ | A1 | 3.05% |

| | | |
|---|---|---|
| A | A2 | 2.85% |
| A- | A3 | 2.60% |
| BBB+ | Baa1 | 2.30% |
| BBB | Baa2 | 1.90% |
| BBB- | Baa3 | 1.20% |
| Below BBB- | Below Baa3 | 0.00% |

An entity's "Tangible Net Worth" for purposes of the ISO New England Financial Assurance Policy on any date 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.

**b. Market Credit Limit for Unrated Non-Municipal Market Participants**

The Market Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net Worth, (ii) $25 million or (iii) 20 percent (20%) of TADO. The Market Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

**2. Market Credit Limit for Municipal Market Participants**

The Market Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to the lesser of (i) 20 percent (20%) of TADO and (ii) $25 million. The Market Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum

of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

**E. Transmission Credit Limits**

A "Transmission Credit Limit" shall be established for each Market Participant in accordance with this Section II.E, which Transmission Credit Limit shall apply in accordance with this Section II.E. A Transmission Credit Limit may not be used to meet FTR Financial Assurance Requirements.

**1. Transmission Credit Limit for Rated Non-Municipal Market Participants**

The Transmission Credit Limit of each Rated Non-Municipal Market Participant shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table or (ii) $50 million:

| **Investment Grade Rating** | | **Percentage of Tangible Net Worth** |
|---|---|---|
| **S&P/Fitch** | **Moody's** | |
| AAA | Aaa | 5.50% |
| AA+ | Aa1 | 5.50% |
| AA | Aa2 | 4.50% |
| AA- | Aa3 | 4.00% |
| A+ | A1 | 3.05% |
| A | A2 | 2.85% |
| A- | A3 | 2.60% |
| BBB+ | Baa1 | 2.30% |
| BBB | Baa2 | 1.90% |
| BBB- | Baa3 | 1.20% |
| Below BBB- | Below Baa3 | 0.00% |

**2. Transmission Credit Limit for Unrated Non-Municipal Market Participant**

The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net

Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

**3. Transmission Credit Limit for Municipal Market Participants**

The Transmission Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to $25 million. The Transmission Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

**F. Credit Limits for FTR-Only Customers**

The Market Credit Limit and Transmission Credit Limit of each FTR-Only Customer shall be $0.

**G. Total Credit Limit**

The sum of a Rated Non-Municipal Market Participant's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Municipal Market Participant that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the limit set forth in Section II.D.1.a above) and its Transmission Credit Limit (up to the limit set forth in Section II.E.1 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Municipal Market Participant may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Municipal Market Participant does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate,

or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

## III. MARKET PARTICIPANTS' REQUIREMENTS

Each Market Participant that provides the ISO with financial assurance pursuant to this Section III must provide the ISO with financial assurance in one of the forms described in Section X below and in an amount equal to the amount required in order to avoid suspension under Section III.B below (the "Market Participant Financial Assurance Requirement"). A Market Participant's Market Participant Financial Assurance Requirement shall remain in effect as provided herein until the later of (a) 150 days after termination of the Market Participant's membership or (b) the end date of all FTRs awarded to the Market Participant and the final satisfaction of all obligations of the Market Participant providing that financial assurance; provided, however that financial assurances required by the ISO New England Financial Assurance Policy related to potential billing adjustments chargeable to a terminated Market Participant shall remain in effect until such billing adjustment request is finally resolved in accordance with the provisions of the ISO New England Billing Policy. Furthermore and without limiting the generality of the foregoing, (i) any portion of any financial assurance provided under the ISO New England Financial Assurance Policy that relates to a Disputed Amount shall not be terminated or returned prior to the resolution of such dispute, even if the Market Participant providing such financial assurance is terminated or voluntarily terminates its MPSA and otherwise satisfies all of its obligations to the ISO and (ii) the ISO shall not return or permit the termination of any financial assurance provided under the ISO New England Financial Assurance Policy by a Market Participant that has terminated its membership or been terminated to the extent that the ISO determines in its reasonable discretion that that financial assurance will be required under the ISO New England Financial Assurance Policy with respect to an unsettled liability or obligation owing from that Market Participant.

A Market Participant that knows that it is not satisfying its Market Participant Financial Assurance Requirement shall notify the ISO immediately of that fact.

### A. Determination of Financial Assurance Obligations

For purposes of the ISO New England Financial Assurance Policy:

(i) a Market Participant's "Hourly Requirements" at any time will be the sum of (x) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Hourly

Charges (excluding Daily FCM Charges) for such Market Participant that have been settled but not invoiced, plus (z) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been cleared but not settled which amount shall be calculated by the Hourly Charges Estimator. The Hourly Charges Estimator (which amount shall not be less than $0) shall be determined by the following formula:

$$\text{Hourly Charges Estimator} = \sum_{i=t-n+1}^{t} HC_i \times \text{LMP ratio} \times 1.15$$

Where:

t = The last day that such Market Participant's Hourly Charges (excluding Daily FCM Charges) are fully settled;

n = The number of days that such Market Participant's Day-Ahead Energy has been cleared but not settled;

HC = The Hourly Charges (excluding Daily FCM Charges) for such Market Participant for a fully settled day; and

LMP ratio = The average Day-Ahead Prices at the New England Hub over the period of cleared but not settled n days divided by the average Day-Ahead Prices at the New England Hub over the period of most recent fully settled n days. For purposes of this Section III.A.(i), the "New England Hub" shall mean the Hub located in Western and Central Massachusetts referred to as .H.INTERNAL_HUB;

(ii) A Market Participant's "Daily FCM Requirements" at any time will be the sum of (x) the Daily FCM Charges that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Daily FCM Charges that have been settled but not invoiced, plus (z) the Daily FCM Charges for such Market Participant that have been incurred but not settled which amount shall be calculated by the Daily FCM Obligation Estimator. The Daily FCM Obligation Estimator (which amount shall not be less than $0) shall be determined by the following formula:

Daily FCM Obligation Estimator = MAX(FCM_Daily_Credit_CM x NDAY_CM + FCM_Daily_Credit_PM x NDAY_PM + FCM_Charge_LD x NDAY_P2 x FCA_Price_Ratio, 0)

Where:

FCM_Daily_Credit_CM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the current month;

FCM_Daily_Credit_PM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the month preceding the current month;

NDAY_CM is the number of days in the current month within the period from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

NDAY_PM is the number of days in the month preceding the current month within the period from the last day of the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

FCM_Charge_LD is the portion of the Daily FCM Charges that corresponds to Capacity Load Obligations for the Market Participant from the last day the Daily FCM Charges have been settled; and

NDAY_P2 is the number of days from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed) plus 2.

The FCA_Price_Ratio shall be calculated as the weighted average of the Capacity Clearing Prices for the Rest-of-Pool Capacity Zone for the relevant Capacity Commitment Periods divided by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day the Daily FCM Charges have been settled, as determined by the following formula:

$$FCA\_Price\_Ratio = (((Clearing\ Price\_CCP_n \times NDAY\_P2\_CCP_n) + (Clearing\ Price\_CCP_{n+1} \times NDAY\_P2\_CCP_{n+1}))/NDAY\_P2)/(Clearing\ Price\_CCP_n)$$

Where:

Clearing Price_$CCP_n$ is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day that the Daily FCM Charges have been settled;

Clearing Price_$CCP_{n+1}$ is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone for the Capacity Commitment Period following $CCP_n$;

NDAY_P2_$CCP_n$ is number of days in the $CCP_n$ within NDAY_P2; and

NDAY_P2_$CCP_{n+1}$ is number of days in the $CCP_{n+1}$ within NDAY_P2.

(iii) a Market Participant's "Non-Hourly Requirements" at any time will be determined by averaging that Market Participant's Non-Hourly Charges but not include: (A) the amount due from or to such Market Participant for FTR transactions, (B) any amounts due from such Market Participant for the Forward Capacity Market, (C) any amounts due under Section 14.1 of the RNA, (D) any amounts due for NEPOOL GIS API Fees, and (E) the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Market Participant) over the two most recently invoiced calendar months; provided that such Non-Hourly Requirements shall in no event be less than zero;

(iv) a Market Participant's "Transmission Requirements" at any time will be determined by averaging that Market Participant's Transmission Charges over the two most recently invoiced calendar months; provided that such Transmission Requirements shall in no event be less than $0;

(v) a Market Participant's Virtual Requirements at any time will equal the amount of all unsettled Increment Offers and Decrement Bids submitted by such Market Participant at such time (which amount of unsettled Increment Offers and Decrement Bids will be calculated by the ISO according to a methodology approved from time to time by the NEPOOL Budget and Finance Subcommittee and posted on the ISO's website);

(vi) a Market Participant's "Financial Assurance Obligations" at any time will be equal to the sum at such time of:

a. such Market Participant's Hourly Requirements; plus
b. such Market Participant's Daily FCM Requirements; plus
c. such Market Participant's Virtual Requirements; plus
d. such Market Participant's Non-Hourly Requirements times 2.50 (subject to Section X.D with respect to Provisional Members); plus
e. such Market Participant's "FTR Financial Assurance Requirements" under Section VI below; plus
f. such Market Participant's "FCM Financial Assurance Requirements" under Section VII below; plus

g. such Market Participant's "IEP Financial Assurance Requirement" under Section III.D below; plus

h. the amount of any Disputed Amounts received by such Market Participant; and

(vii) a Market Participant's "Transmission Obligations" at any time will be such Market Participant's Transmission Requirements times 2.50.

To the extent that the calculations of the components of a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) as described above produce positive and negative values, such components may offset each other; provided, however, that a Market Participant's Financial Assurance Obligations shall never be less than zero.

## B. Credit Test Calculations and Allocation of Financial Assurance, Notice and Suspension from the New England Markets

### 1. Credit Test Calculations and Allocation of Financial Assurance

The financial assurance provided by a Market Participant shall be applied as described in this Section.

(a) "Market Credit Test Percentage" is equal to a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) divided by the sum of its Market Credit Limit and any financial assurance allocated as described in subsection (d) below.

(b) "FTR Credit Test Percentage" is equal to a Market Participant's FTR Financial Assurance Requirements divided by any financial assurance allocated as described in subsection (d) below.

(c) "Transmission Credit Test Percentage" is equal to a Market Participant's Transmission Obligations divided by the sum of its Transmission Credit Limit and any financial assurance allocated as described in subsection (d) below.

(d) A Market Participant's financial assurance shall be allocated as follows:

(i) financial assurance shall be first allocated so as to ensure that the Market Participant's Market Credit Test Percentage is no greater that 100%;

(ii) any financial assurance that remains after the allocation described in subsection (d) (i) shall be allocated so as to ensure that the Market Participant's FTR Credit Test Percentage is no greater than 100%;

(iii) any financial assurance that remains after the allocation described in subsection (d) (ii) shall be allocated so as to ensure that the Market Participant's Transmission Credit Test Percentage is no greater than 100%;

(iv) if any financial assurance remains after the allocations described in subsection (d) (iii), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 89.99%;

(v) if any financial assurance remains after the allocation described in subsection (d) (iv), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 79.99%;

(vi) any financial assurance that remains after the allocations described in subsection (d) (v) shall be allocated to the Market Credit Test Percentage.

**2. Notices**

**a. 80 Percent Test**

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant.

**b. 90 Percent Test**

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) , then, in addition to the actions to be taken when the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant. The ISO shall also issue a 90 percent (90%) notice to a Market Participant and take certain other actions under the circumstances described in Section III.B.2.c below.

**c. 100 Percent Test**

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or when the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equal zero, then, in addition to the actions to be taken when the

Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%) and 90 percent (90%), (i) the ISO shall issue notice thereof to such Market Participant, (ii) that Market Participant shall be immediately suspended from submitting Increment Offers and Decrement Bids until such time when its Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are less than or equal to 100 percent (100%), and (iii) if sufficient financial assurance to lower the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 100 percent (100%) or, in the case of a Market Participant that has received one to five notices that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) in the previous 365 days (not including the instant notice), sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%), is not provided by 8:30 a.m. Eastern Time on the next Business Day, (a) the event shall be a Financial Assurance Default; (b) the ISO shall issue notice thereof to such Market Participant, to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contacts for all Market Participants, and (c) such Market Participant shall be suspended from: (1) the New England Markets, as provided below; (2) receiving transmission service under any existing or pending arrangements under the Tariff or scheduling any future transmission service under the Tariff; (3) voting on matters before the Participants Committee and NEPOOL Technical Committees; (4) entering into any future transactions in the FTR system; and (5) submitting an offer of Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction in the Forward Capacity Market, in each case until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 100 percent (100%) or less. In addition to all of the provisions above, any Market Participant that has received six or more notices in the previous 365 days that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) shall receive a notice thereof and shall be required to maintain sufficient financial assurance to keep such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage at less than or equal to 90

percent (90%). If such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage exceeds 90 percent (90%), the ISO shall issue a notice thereof to such Market Participant. If sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%) is not provided by 8:30 a.m. Eastern Time on the next Business Day, then the consequences described in subsections (a), (b) and (c) of Section III.B.2.c (iii) above shall apply until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 90 percent (90%) or less.

However, when a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or 90 percent (90%), as applicable under this Section III.B.2.c, solely because its Investment Grade Rating is downgraded by one grade and the resulting grade is BBB-/Baa3 or higher, then (x) for five Business Days after such downgrade, such downgrade shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage and (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such downgrade if such Market Participant cures such default within such five Business Day period. When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent solely because a letter of credit is valued at $0 prior to the termination of that letter of credit, as described in Section X.B, then the ISO, in its sole discretion, may determine that: (x) for five Business Days after such change in the valuation of the letter of credit, such valuation shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage; and/or (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such valuation if such Market Participant cures such default within such five Business Day period.

Notwithstanding the foregoing, a Market Participant shall neither (x) receive a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) nor (y) be suspended under this Section

III.B if (i) the amount of financial assurance necessary for that Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to get to 100 percent (100%) or lower is less than $1,000 or (ii) that Market Participant's status with the ISO has been terminated.

**3. Suspension from the New England Markets**

**a. General**

The suspension of a Market Participant, and any resulting annulment, termination or removal of OASIS reservations, removal from the settlement system and the FTR system, suspension of the ability to offer Non-Commercial Capacity or participate in a substitution auction in the Forward Capacity Market, drawing down of financial assurance, rejection of Increment Offers and Decrement Bids, and rejection of bilateral transactions submitted to the ISO, shall not limit, in any way, the ISO's right to invoice or collect payment for any amounts owed (whether such amounts are due or becoming due) by such suspended Market Participant under the Tariff or the ISO's right to administratively submit a bid or offer of a Market Participant's Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction or to make other adjustments under Market Rule 1.

In addition to the notices provided herein, the ISO will provide any additional information required under the ISO New England Information Policy.

Each notice issued by the ISO pursuant to this Section III.B shall indicate whether the subject Market Participant has a registered load asset. If the ISO has issued a notice pursuant to this Section III.B and subsequently the subject Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%), such Market Participant may request the ISO to issue a notice stating such fact. However, the ISO shall not be obligated to issue such a notice unless, in its sole discretion, the ISO concludes that such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%).

Notwithstanding the foregoing, if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will not be issued.

If a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will be issued only to such Market Participant, and such Market Participant shall be "suspended" as described below.

Any such suspension as a result of one or more Increment Offers or Decrement Bids submitted by a Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, shall take effect immediately upon submission of such Increment Offers and/or Decrement Bids or such bilateral transactions to remain in effect until such Market Participant is in compliance with the ISO New England Financial Assurance Policy, notwithstanding any provision of this Section III.B to the contrary.

If a Market Participant is suspended from the New England Markets in accordance with the provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy, then the provisions of this Section III.B shall control notwithstanding any other provision of the Tariff to the contrary. A suspended Market Participant shall have no ability so long as it is suspended (i) to be reflected in the ISO's settlement system, including any bilateral transactions, as either a purchaser or a seller of any products or services sold through the New England Markets (other than (A) Commercial Capacity and (B) Non-Commercial Capacity during the Non-Commercial

Capacity Cure Period) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the Market Participants, (ii) to submit Demand Bids, Decrement Bids or Increment Offers in the New England Markets, (iii) to submit offers for Non-Commercial Capacity in any Forward Capacity Auction or reconfiguration auction or acquire Non-Commercial Capacity through a Capacity Supply Obligation Bilateral, or (iv) to submit supply offers or demand bids in any Forward Capacity Market substitution auction. Any transactions, including bilateral transactions with a suspended Market Participant (other than transactions for (A) Commercial Capacity and (B) Non-Commercial Capacity during the Non-Commercial Capacity Cure Period) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the other Market Participants and any Demand Bids, Decrement Bids, Increment Offers, and Export Transactions submitted by a suspended Market Participant shall be deemed to be terminated for purposes of the Day-Ahead Energy Market clearing and the ISO's settlement system. If a Market Participant has provided the financial assurance required for a Capacity Supply Obligation Bilateral or Annual Reconfiguration Transaction, then that Capacity Supply Obligation Bilateral or Annual Reconfiguration Transaction, respectively, will not be deemed to be terminated when that Market Participant is suspended.

**b. Load Assets**

Any load asset registered to a suspended Market Participant shall be terminated, and the obligation to serve the load associated with such load asset shall be assigned to the relevant unmetered load asset(s) unless and until the host Market Participant for such load assigns the obligation to serve such load to another asset. If the suspended Market Participant is responsible for serving an unmetered load asset, such suspended Market Participant shall retain the obligation to serve such unmetered load asset. If a suspended Market Participant has an ownership share of a load asset, such ownership share shall revert to the Market Participant that assigned such ownership share to such suspended Market Participant. If a suspended Market Participant has the obligation under the Tariff or otherwise to offer any of its supply or to bid any pumping load to provide products or services sold through the New England Markets, that obligation shall continue, but only in Real-Time, notwithstanding the Market Participant's suspension, and such offer or bid, if cleared under the Tariff, shall be effective.

**c. FTRs**

If a Market Participant is suspended from entering into future transactions in the FTR system, such Market Participant shall retain all FTRs held by it but shall be prohibited from acquiring any additional FTRs during the course of its suspension. It is intended that any suspension under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy will occur promptly, and the definitive timing of any such suspension shall be determined by the ISO from time to time as reported to the NEPOOL Budget and Finance Subcommittee, and shall be posted on the ISO website.

**d. Virtual Transactions**

Notwithstanding the foregoing, if a Market Participant is suspended in accordance with the provisions of the ISO New England Financial Assurance Policy as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant and, but for such Increment Offers and/or Decrement Bids, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, then such suspension shall be limited to (i) the immediate "last in, first out" rejection of pending individual uncleared Increment Offers and Decrement Bids submitted by that Market Participant (it being understood that Increment Offers and Decrement Bids are batched by the ISO in accordance with the time, and that Increment Offers and Decrement Bids will be rejected by the batch); and (ii) the suspension of that Market Participant's ability to submit additional Increment Offers and Decrement Bids unless and until it has complied with the ISO New England Financial Assurance Policy, and the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of that Market Participant after giving effect to the immediate rejection of that Market Participant's Increment Offers and Decrement Bids described in clause (i).

**e. Bilateral Transactions**

If the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equals zero and that Market Participant would be in compliance with the ISO New England Financial Assurance Policy but for the submission of bilateral transactions to the ISO to which the Market Participant is a party, or if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent as a result of one or more bilateral transactions submitted to the ISO to which the Market Participant is a party, then the consequences described in subsection (a) above shall be limited to: (i) rejection of any pending bilateral transactions to which a Market Participant is a party that cause the Market Participant to incur a financial obligation in the ISO's settlement system or any

liability to the ISO, NEPOOL, or the Market Participants, such that the aggregate value of the pending bilateral transactions submitted by all Market Participants is maximized (recognizing the downstream effect that rejection of a bilateral transaction may have on the Market Credit Test Percentages, FTR Credit Test Percentages, or Transmission Credit Test Percentages of other Market Participants), while ensuring that the financial assurance requirements of each Market Participant are satisfied; and (ii) suspension of that Market Participant's ability to submit additional bilateral transactions until it has complied with the ISO New England Financial Assurance Policy (the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of the Market Participant after giving effect to the immediate rejection of the bilateral transactions to which the Market Participant is a party as described in clause (i) above). In the case of a bilateral transaction associated with the Day-Ahead Energy Market, the ISO will provide notice to a Market Participant that would be in default of the ISO New England Financial Assurance Policy as a result of the bilateral transaction, and the consequences described in clauses (i) and (ii) above shall only apply if the Market Participant fails to cure its default by 6:00 p.m. Eastern Time of that same Business Day. In the case of a Capacity Load Obligation Bilateral, the consequences described in clauses (i) and (ii) above shall apply if the Market Participant does not cure its default within one Business Day after notification that a Capacity Load Obligation Bilateral caused the default. Bilateral transactions that transfer Forward Reserve Obligations and Supplemental Availability Bilaterals are not subject to the provisions of this Section III.B.3(e).

**4. Serial Notice and Suspension Penalties**

If either (x) a Market Participant is suspended from the New England Markets because of a failure to satisfy its Financial Assurance Requirements in accordance with the provisions of the ISO New England Financial Assurance Policy or (y) a Market Participant receives more than five notices that its Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage has exceeded 100 percent (100%) in any rolling 365-day period, then such Market Participant shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 365-day period. If a Market Participant receives a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) in the same day, then only one of those notices will count towards the

five notice limit. All penalties paid under this paragraph shall be deposited in the Late Payment Account maintained under the ISO New England Billing Policy.

**C. Additional Financial Assurance Requirements for Certain Municipal Market Participants**

Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, a Credit Qualifying Municipal Market Participant that is not a municipality (which, for purposes of this Section III.C, does not include an agency or subdivision of a municipality) must provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation, unless either: (1) that Credit Qualifying Municipal Market Participant has a corporate Investment Grade Rating from one or more of the Rating Agencies; or (2) that Credit Qualifying Municipal Market Participant has an Investment Grade Rating from one or more of the Rating Agencies for all of its rated indebtedness; or (3) that Credit Qualifying Municipal Market Participant provides the ISO with an opinion of counsel that is acceptable to the ISO confirming that amounts due to the ISO under the Tariff have priority over, or have equal priority with, payments due on the debt on which the Credit Qualifying Municipal Market Participant's Investment Grade Rating is based. Each legal opinion provided under clause (3) of this Section III.C will be updated no sooner than 60 days and no later than 30 days before each reconfiguration auction that precedes a Capacity Commitment Period to which such legal opinion relates, and if that update is not provided or that update is not acceptable to the ISO, the applicable Credit Qualifying Municipal Market Participant must either satisfy one of the other clauses of this Section III.C or provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation.

**D. Inventoried Energy Program Financial Assurance Requirement**

Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, if any Market Participant has submitted a Forward Energy Inventory Election approved by the ISO under Section III.K.1.1 of the Tariff, such Market Participant shall be subject to the additional financial assurance requirements of this section. Any such Market Participant must provide additional financial assurance in one of the forms described in Section X below in an

amount equal to the Inventoried Energy Program Financial Assurance Requirement on or before December 1 of each program year. The Inventoried Energy Program Financial Assurance Requirement will be calculated on a daily basis for each program year, from December 1, 2023 through February 29, 2024 and separately from December 1, 2024 through February 28, 2025, as follows:

IEP Financial Assurance Requirement = MAX(0, FE_MWh - Q_MWh) * D_95 * MF * SPR

Where:

FE_MWh = is the amount of Forward Energy Inventory elected by the Market Participant;

Q_MWh = is the maximum observed physical inventory over the prior 15 days;

D_95 = is the 95th percentile of observed Inventoried Energy Days, which for the 2023-2024 and 2024-2025 program years shall be 19;

MF = is the month factor, which shall be 100% for December, 87% for January, and 26% for February; and

SPR = spot payment rate = the $/MWh rate used in the calculation of Inventoried Energy Spot Payments as described in Section III.K.3.2 of the Tariff.

## IV. CERTAIN NEW AND RETURNING MARKET PARTICIPANTS REQUIREMENTS

A new Market Participant or 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 (a "Returning Market Participant") is required to provide the ISO, for three months in the case of a new Market Participant and six months in the case of a Returning Market Participant, financial assurance in one of the forms described in Section X below equal to any amount of additional financial assurance required to meet the capitalization requirements described in Section II.A.4 plus the greater of (a) its Financial Assurance Requirement or (b) its "Initial Market Participant Financial Assurance Requirement." A new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement must be provided to the ISO no later than one Business Day before commencing activity in the New England Markets or commencing transmission service under the Tariff, and shall be determined by the following formula:

$$FAR = G + T + L + E$$

Where FAR is the Initial Market Participant Financial Assurance Requirement and G, T, L and E are determined by the following formulas:

$G = (MW_g \times Hr_{DA} \times D \times 3.25) + (MW_g \times Hr_{MIS} \times S_2 \times 3.25)$;

Where:

$MW_g$ = Total nameplate capacity of the Market Participant's generation units that have achieved commercial operation;

$Hr_{DA}$ = The number of hours of generation that any such generation unit could be bid in the Day-Ahead Energy Market before it could be removed if such unit tripped, as determined by the ISO in its sole discretion;

D = The maximum observed differential between Energy prices in the Day-Ahead and Real-Time Energy Markets during the prior calendar year ("Maximum Energy Price Differential"), as determined by the ISO in its sole discretion;

$Hr_{MIS}$ = The standard number of hours between generation and the issuance of initial Market Information Server ("MIS") settlement reports including projected generation activity for such units, as determined by the ISO in its sole discretion; and

$S_2$ = The per MW amount assessed pursuant to Schedule 2 of Section IV.A of this Tariff, as determined by the ISO.

T = $MW_t \times Hr_{MIS} \times (D + S_{2\text{-}3}) \times 3.25$;

Where: $MW_t$ = Number of MWs to be traded in the New England Markets as reasonably projected by the new Market Participant or the Returning Market Participant;

$Hr_{MIS}$ = The standard number of hours between generation and the issuance of initial MIS settlement reports including projected generation activity, as determined by the ISO in its sole discretion;

D = Maximum Energy Price Differential; and

$S_{2-3}$ = The per MWh amount assessed pursuant to Schedules 2 and 3 of Section IV.A of the Tariff, as determined annually by the ISO.

$$L = (MW_1 \times LF \times Hr_{MIS} \times (EP + S_{2-3}) \times 3.25) + (MW_1 \times Hr_{MIS} \times TC \times 3.25)$$

Where:

$MW_1$ = MWs of Real-Time Load Obligation (as defined in Market Rule 1) of the new Market Participant or Returning Market Participant;

LF = Average load factor in New England, as determined annually by the ISO in its sole discretion;

$Hr_{MIS}$ = The standard number of hours between generation and the issuance of initial MIS settlement reports including projected generation activity, as determined by the ISO in its sole discretion;

EP = The average price of Energy in the Day-Ahead Energy Market for the most recent calendar year for which information is available from the Annual Reports published by the ISO, as determined by the ISO in its sole discretion;

$S_{2-3}$ = The per MW amount assessed pursuant to Schedules 2 and 3 of Section IV.A of the Tariff, as determined annually by the ISO; and

TC = The hourly transmission charges per $MW_1$ assessed under the Tariff (other than Schedules 1, 8 and 9 of Section II of the Tariff), as determined annually by the ISO.

$$E = (SE) \times 3.25$$

Where:

SE = Average monthly share of Participant Expenses for the applicable Sector.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV is 80 percent or more of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equaled or exceeded 80 percent (80%) under Section III.B above.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV is 90 percent or more of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equaled or exceeded 90 percent (90%) under Section III.B above.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV exceeds 100 percent of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeded 100 percent (100%) under Section III.B above.

## V. NON-MARKET PARTICIPANT TRANSMISSION CUSTOMERS REQUIREMENTS

### A. Ongoing Financial Review and Credit Ratings

#### 1. Rated Non-Market Participant Transmission Customer and Transmission Customers

Each Rated Non-Market Participant Transmission Customer that does not currently have an Investment Grade Rating must provide an appropriate form of financial assurance as described in Section X below.

**2. Unrated Non-Market Participant Transmission Customers**

Any Unrated Non-Market Participant Transmission Customer that (i) has defaulted on any of its obligations under the Tariff (including without limitation its obligations hereunder and under the ISO New England Billing Policy) during the immediately preceding 365-day period; or (ii) does not have a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 must provide an appropriate form of financial assurance as described in Section X below. An Unrated Non-Market Participant Transmission Customer that does not meet either of the conditions described in clauses (i) and (ii) of this paragraph is referred to herein as satisfying the "NMPTC Credit Threshold."

**B. NMPTC Credit Limits**

**1. NMPTC Market Credit Limit**

A Market Credit Limit shall be established for each Non-Market Participant Transmission Customer as set forth in this Section V.B.1.

The Market Credit Limit of each Rated Non-Market Participant Transmission Customer shall at any time be equal to the least of: (i) the applicable percentage of such Rated Non-Market Participant Transmission Customer's Tangible Net Worth (as reflected in the following table); (ii) $50 million; or (iii) 20 percent (20%) of TADO:

| **Investment Grade Rating** | | **Percentage of Tangible Net Worth** |
|---|---|---|
| **S&P/Fitch** | **Moody's** | |
| AAA | Aaa | 5.50% |
| AA+ | Aa1 | 5.50% |
| AA | Aa2 | 4.50% |
| AA- | Aa3 | 4.00% |
| A+ | A1 | 3.05% |

| | | |
|---|---|---|
| A | A2 | 2.85% |
| A- | A3 | 2.60% |
| BBB+ | Baa1 | 2.30% |
| BBB | Baa2 | 1.90% |
| BBB- | Baa3 | 1.20% |
| Below BBB- | Below Baa3 | 0.00% |

The Market Credit Limit of each Unrated Non-Market Participant Transmission Customer that satisfies the NMPTC Credit Threshold shall at any time be equal to the least of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Market Participant Transmission Customer's Tangible Net Worth, (ii) $25 million or (iii) 20 percent (20%) of TADO. The Market Credit Limit of each Unrated Non-Market Participant Transmission Customer that does not satisfy the NMPTC Credit Threshold shall be $0.

**2. NMPTC Transmission Credit Limit**

A Transmission Credit Limit shall be established for each Non-Market Participant Transmission Customer in accordance with this Section V.B.2.

The Transmission Credit Limit of each Rated Non-Market Participant Transmission Customer shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Market Participant Transmission Customer's Tangible Net Worth as listed in the following table or (ii) $50 million:

| **Investment Grade Rating** | | **Percentage of Tangible Net Worth** |
|---|---|---|
| **S&P/Fitch** | **Moody's** | |
| AAA | Aaa | 5.50% |
| AA+ | Aa1 | 5.50% |
| AA | Aa2 | 4.50% |
| AA- | Aa3 | 4.00% |
| A+ | A1 | 3.05% |
| A | A2 | 2.85% |
| A- | A3 | 2.60% |
| BBB+ | Baa1 | 2.30% |
| BBB | Baa2 | 1.90% |

| | | |
|---|---|---|
| BBB- | Baa3 | 1.20% |
| Below BBB- | Below Baa3 | 0.00% |

The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that satisfies the NMPTC Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Market Participant Transmission Customer's Tangible Net Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that does not satisfy the NMPTC Credit Threshold shall be $0.

**3. NMPTC Total Credit Limit**

The sum of a Non-Market Participant Transmission Customer's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Market Participant Transmission Customer that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the amount set forth in Section V.B.1 above) and its Transmission Credit Limit (up to the amount set forth in Section V.B.2 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Market Participant Transmission Customer may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Market Participant Transmission Customer does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate, or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

**C. Information Reporting Requirements for Non-Market Participant Transmission Customers**

Each Rated Non-Market Participant Transmission Customer having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis, within 10 days of their becoming available and within 65 days after the end of the applicable fiscal quarter of such Rated Non-Market Participant Transmission Customer, its balance sheet, which shall show sufficient detail for the ISO to assess the Rated Non-Market Participant Transmission Customer's Tangible Net Worth. In addition, each Rated Non-Market Participant Transmission Customer that has an Investment Grade Rating having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of their becoming available and within 120 days after the end of the fiscal year of such Rated Non-Market Participant Transmission Customer, balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). If any of this financial information is available on the internet, the Rated Non-Market Participant Transmission Customer may provide instead a letter to the ISO stating where such information may be located and retrieved.

Each Unrated Non-Market Participant Transmission Customer having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis, within 10 days of their becoming available and within 65 days after the end of the applicable fiscal quarter of such Unrated Non-Market Participant Transmission Customer, its balance sheet, which shall show sufficient detail for the ISO to assess the Unrated Non-Market Participant Transmission Customer's Tangible Net Worth. Unrated Non-Market Participant Transmission Customers having a Market Credit Limit or Transmission Credit Limit greater than $0 shall also provide additional financial statements, which shall show

sufficient detail for the ISO to calculate such Unrated Non-Market Participant Transmission Customer's Current Ratio, Debt-to-Total Capitalization Ratio and EBITDA-to-Interest Expense Ratio. In addition, each such Unrated Non-Market Participant Transmission Customer that satisfies the Credit Threshold and has a Market Credit Limit or Transmission Credit Limit of greater than $0 or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of becoming available and within 120 days after the end of the fiscal year of such Unrated Non-Market Participant Transmission Customer balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). Where any of the above financial information is available on the internet, the Unrated Non-Market Participant Transmission Customer may provide the ISO with a letter stating where such information may be located and retrieved.

If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-along subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; (iii) compiled statements; (iv) internally prepared statements; or (v) tax returns).

Except in the case of a Non-Market Participant Transmission Customer that submits audited financial statements to the ISO, financial statements submitted to the ISO pursuant to this Section V.C shall be accompanied by a written statement from a Senior Officer of the Non-Market Participant Transmission Customer certifying the accuracy of those financial statements. If an attestation was made by an independent accounting firm, then the written statement shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required.

Notwithstanding any other provision in this subsection, the ISO may require any Non-Market Participant Transmission Customer to submit the financial statements and other information described in this subsection. The Non-Market Participant Transmission Customer shall provide the requested statements and other information within 10 days of such request. If a Non-Market Participant Transmission Customer fails to provide financial statements or other information as requested and the ISO determines that the Non-Market Participant Transmission Customer poses an unreasonable risk to the New England Markets, then the ISO may request that the Non-Market Participant Transmission Customer provide additional financial assurance in an amount no greater than $10 million, or take other measures to substantiate the Non-Market Participant Transmission Customer's ability to safely transact in the New England Markets (any additional financial assurance provided pursuant to this Section V.C shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy). If the Non-Market Participant Transmission Customer fails to comply with such a request from the ISO, then the ISO may issue a notice of suspension or termination to the Non-Market Participant Transmission Customer. If the Non-Market Participant Transmission Customer fails to comply with the ISO's request within 5 Business Days from the date of issuance of the notice of suspension or termination, then the ISO may suspend or terminate the Non-Market Participant Transmission Customer.

A Non-Market Participant Transmission Customer may choose not to submit financial statements as described in this Section V.C, in which case the ISO shall use a value of $0.00 for the Non-Market Participant Transmission Customer's total assets and Tangible Net Worth for purposes of the capitalization assessment described in Section II.A.4(a) and such Non-Market Participant Transmission Customer's Market Credit Limit and Transmission Credit Limit shall be $0.00.

A Non-Market Participant Transmission Customer may choose to provide additional financial assurance in an amount equal to $10 million in lieu of providing financial statements under this Section V.C. Such amount shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy but shall be sufficient to meet the capitalization requirements in Section II.A.4(a)(iii).

**D. Financial Assurance Requirement for Non-Market Participant Transmission Customers**

Each Non-Market Participant Transmission Customer that provides additional financial assurance pursuant to the ISO New England Financial Assurance Policy must provide the ISO with financial assurance in one of the forms described in Section X below and in the amount described in this Section V.D (the "NMPTC Financial Assurance Requirement").

**1. Financial Assurance for ISO Charges**

Each Non-Market Participant Transmission Customer must provide the ISO with additional financial assurance such that the sum of its Market Credit Limit and that additional financial assurance shall at all times be at least equal to the sum of:

(i) two and one-half (2.5) times the average monthly Non-Hourly Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0); plus

(ii) amount of any unresolved Disputed Amounts received by such Non-Market Participant Transmission Customer.

**2. Financial Assurance for Transmission Charges**

Each Non-Market Participant Transmission Customer must provide the ISO with additional financial assurance hereunder such that the sum of (x) its Transmission Credit Limit and (y) the excess of (A) the available amount of the additional financial assurance provided by that Non-Market Participant Transmission Customer over (B) the amount of that additional financial assurance needed to satisfy the requirements of Section V.D.1 above is equal to two and one-half (2.5) times the average monthly Transmission Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0)

**3. Notice of Failure to Satisfy NMPTC Financial Assurance Requirement**

A Non-Market Participant Transmission Customer that knows or can reasonably be expected to know that it is not satisfying its NMPTC Financial Assurance Requirement shall notify the ISO immediately of that fact. Without limiting the availability of any other remedy or right hereunder, failure by any Non-Market Participant Transmission

Customer to comply with the provisions of the ISO New England Financial Assurance Policy (including failure to satisfy its NMPTC Financial Assurance Requirement) may result in the commencement of termination of service proceedings against that non-complying Non-Market Participant Transmission Customer.

## VI. ADDITIONAL PROVISIONS FOR FTR TRANSACTIONS

Market Participants must complete an ISO-prescribed training course prior to participating in the FTR Auction. All Market Participants transacting in the FTR Auction that are otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, including all FTR-Only Customers ("Designated FTR Participants") are required to provide financial assurance in an amount equal to the sum of the FTR Settlement Risk Financial Assurance, the Unsettled FTR Financial Assurance, and the Settlement Financial Assurance, each as described in this Section VI (such sum being referred to in the ISO New England Financial Assurance Policy as the "FTR Financial Assurance Requirements").

### A. FTR Settlement Risk Financial Assurance

A Designated FTR Participant is required to provide "FTR Settlement Risk Financial Assurance" for each bid it submits into an FTR Auction and for each FTR that is awarded to it in an FTR Auction, as described below.

After bids are finalized for an FTR Auction, but before the auction results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on its bids for each FTR path. The ISO will calculate an FTR Settlement Risk Financial Assurance amount for each direction (prevailing flow and counter flow) of each FTR path on which the Designated FTR Participant has bid, equal to the total number of MW bid for that direction of the FTR path multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the bid. For that FTR path, the Designated FTR Participant must provide FTR Settlement Risk Financial Assurance equal to the higher of the amounts calculated for each direction.

Once an FTR Auction's results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on awarded FTRs, equal to the MW value of each awarded FTR multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the FTR. For

purposes of this calculation, the ISO will net the MW values of a Designated FTR Participant's awarded FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak). For purposes of this netting, annual FTRs may be converted into monthly positions.

The proxy value for each FTR path, which shall be calculated separately for on-peak and off-peak FTRs, will be based on the standard deviation observed in the difference between the average congestion components of the Locational Marginal Price in the Day-Ahead Energy Market at the path's sink and source for the previous 36 months, with differing multipliers for annual and monthly FTRs and for prevailing flow and counter flow paths. These multipliers will be reviewed and approved by the NEPOOL Budget and Finance Subcommittee and shall be posted on the ISO's website. Where there is insufficient data to perform these calculations for a node, zonal data will be used instead.

FTR Settlement Risk Financial Assurance will be adjusted as the awarded FTRs are settled. In no event will the FTR Settlement Risk Financial Assurance be less than $0.

**B. Unsettled FTR Financial Assurance**

A Designated FTR Participant is required to maintain, at all times, "Unsettled FTR Financial Assurance" for all FTRs awarded to it in any FTR Auctions. Immediately after FTRs are awarded in an FTR Auction, the Unsettled FTR Financial Assurance for those FTRs shall be zero. After subsequent FTR Auctions, the Unsettled FTR Financial Assurance for each FTR awarded in a previous FTR Auction shall be adjusted to reflect any change in the clearing price for that FTR based on non-zero volume. The adjustment will be equal to the change in the clearing price multiplied by the number of MW of the previously awarded FTR, with increases in the clearing price reducing the Unsettled FTR Financial Assurance amount and decreases in the clearing price increasing the Unsettled FTR Financial Assurance amount. For purposes of these calculations, the ISO will consider FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak) together. A Designated FTR Participant's Unsettled FTR Financial Assurance may be a charge or a credit, and in the case of a credit, may offset the Designated FTR Participant's other FTR Financial Assurance Requirements (but not to less than zero). A Designated FTR Participant's Unsettled FTR Financial Assurance will be adjusted as the awarded FTRs are settled.

**C. Settlement Financial Assurance**

A Designated FTR Participant that has been awarded a bid in an FTR Auction is required to provide "Settlement Financial Assurance." The amount of a Designated FTR Participant's Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement. Additionally, when the Designated FTR Participant is invoiced and the net of the charges incurred by such Designated FTR Participant for FTR transactions and the amount due to such Market Participant for FTR transactions results in a net charge, the amount of the net charge shall be added to the Designated FTR Participant's Settlement Financial Assurance until the invoice is paid.

**D. Consequences of Failure to Satisfy FTR Financial Assurance Requirements**

If a Designated FTR Participant does not have additional financial assurance equal to its FTR Financial Assurance Requirements (in addition to its other financial assurance obligations hereunder) in place at the time an FTR Auction into which it has bid closes, then, in addition to the other consequences described in the ISO New England Financial Assurance Policy, all bids submitted by that Designated FTR Participant for that FTR Auction will be rejected. The Designated FTR Participant will be allowed to participate in the next FTR Auction held provided it meets all requirements for such participation, including without limitation those set forth herein. Each Designated FTR Participant must maintain the requisite additional financial assurance equal to its FTR Financial Assurance Requirements for the duration of the FTRs awarded to it. The amount of any additional financial assurance provided by a Designated FTR Participant in connection with an unsuccessful bid in an FTR Auction which, as a result of such bid being unsuccessful, is in excess of its FTR Financial Assurance Requirements will be held by the ISO and will be applied against future FTR bids by and awards to that Designated FTR Participant unless that Designated FTR Participant requests in writing to have such excess financial assurance returned to it. Prior to returning any financial assurance to a Designated FTR Participant, the ISO shall use such financial assurance to satisfy any overdue obligations of that Designated FTR Participant. The ISO shall only return to that

Designated FTR Participant the balance of such financial assurance after all such overdue obligations have been satisfied.

## VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy (each a "Designated FCM Participant"), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the "FCM Financial Assurance Requirements"). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.

### A. FCM Delivery Financial Assurance

Each Designated FCM Participant that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter, shall be subject to a "Corporate Liquidity Assessment" as described in this Section VII.A to determine its FCM Delivery Financial Assurance.

#### 1. FCM Delivery Financial Assurance Calculation

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant's FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero.

FCM Delivery Financial Assurance is calculated according to the following formula for a Designated FCM Participant that has a Capacity Supply Obligation up to and including the end of the Capacity Commitment Period associated with the fifteenth Forward Capacity Auction:

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

FCM Delivery Financial Assurance is calculated according to the following applicable formula for a Designated FCM Participant that has a Capacity Supply Obligation commencing at the beginning of the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction and every Capacity Commitment Period thereafter. The applicable FCM Delivery Financial Assurance formula is determined by the results of a Corporate Liquidity Assessment and is limited by the operation of the applicable stop-loss mechanisms as set forth in Market Rule 1 (including those that may apply in the next Capacity Commitment Period).

Corporate Liquidity Assessment Result: Low Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

Corporate Liquidity Assessment Result: Medium Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1]

Corporate Liquidity Assessment Result: High Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1] – Second Largest Monthly Stop-loss x max[(ABR – CWAP), 0.1]

Where:

MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, which have not yet been invoiced in instances where the MCC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MCC is a charge to the Designated FCM Participant. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

IMC (intra-month collateral) equals estimated monthly capacity payments incurred during the current delivery month as limited by the difference (which shall in no event be less than zero) between (A) the minimum of the applicable monthly stop-loss and the remaining annual stop-loss as described in Section III.13.7.3.1 and Section III.13.7.3.2 of Market Rule 1, respectively, and (B) the amount of additional FCM Delivery Financial Assurance when considering the Designated FCM Participant's current month FCM Delivery Financial Assurance obligation as compared to the Designated FCM Participant's next month FCM Delivery Financial Assurance obligation, in each case without giving effect to the IMC and MCC variables when calculating such additional amount. Where the estimated monthly capacity payments for each Designated FCM Participant, shall be updated three (3) days after publication of the most recent FCM Preliminary Capacity Performance Score report (or equivalent report) on the Market Information Server.

DFAMW (delivery financial assurance MW) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.

PE (potential exposure) is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the current Capacity Commitment Period and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7 of Market Rule 1, the Forward

Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. For the purpose of calculating the ABR, all Capacity Balancing Ratios, including Capacity Balancing Ratios for Capacity Scarcity Conditions that occurred in past Capacity Commitment Periods or in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, shall be calculated utilizing the Capacity Balancing Ratio formula that is currently effective, as described in Section III.13.7.2.3 or Section III.15.8.2.3 of Market Rule 1. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60.

CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months

in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall equal 0.65; the temporary average performance for all other resources shall equal 1.00. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

| | |
|---|---|
| June and December | 2.000; |
| July and January | 1.732; |
| August and February | 1.414; |
| All other months | 1.000. |

Peak Monthly Stop-loss equals the largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

Second Largest Monthly Stop-loss equals the second largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

**2. Corporate Liquidity Assessment Methodology**

The ISO will perform a "Corporate Liquidity Assessment" to determine the appropriate liquidity risk assessment category for each Designated FCM Participant (i.e., low risk,

medium risk, or high risk) that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter.

(a) For each Designated FCM Participant, the Corporate Liquidity Assessment shall be performed as follows:
- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest but greater than or equal to the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered medium risk; and
- When the Available Corporate Liquidity is less than the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered high risk.

(b) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from the same Affiliate, or for Designated FCM Participants that are also providing a guaranty (in accordance with this Section VII.A) for an Affiliate:
- The respective Designated FCM Participants will be assessed as a whole and will be collectively assigned one Corporate Liquidity Assessment result (i.e., low risk, medium risk, or high risk);
- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest aggregated Applicable Monthly Stop-losses but is greater than or equal to the sum of two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered medium risk; and

- When the Available Corporate Liquidity is less than the sum of the two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered high risk.

(c) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from multiple Affiliates:

- The guarantors' financial statements will be considered on an aggregate basis for purposes of the Available Corporate Liquidity calculation taking into account other guaranties provided by any such guarantor under this Section VII.A.

Where:

Calculation Period is the current delivery month through the following five consecutive months.

The Applicable Monthly Stop-loss equals the sum of the monthly stop-losses for each resource in a Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1 for the corresponding months within the Calculation Period.

Available Corporate Liquidity is the sum of unrestricted cash and cash equivalents; marketable securities and money market instruments; undrawn committed credit facilities not expiring within three months of the date of the applicable financial statements; and excess financial assurance. Other than with respect to excess financial assurance, such values shall be (a) as reflected on the most recent financial statements provided by the Designated FCM Participant, provided that such financial statements were provided for the most recently completed financial reporting period and compliant with the requirements of this Section VII.A, and (b) calculated in accordance with international accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied. Excess financial assurance shall be calculated as any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant covering its FCM Delivery Financial Assurance obligations plus any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant in excess of its total

Financial Assurance Obligations, each as reflected in the ISO's Financial Assurance Management (FAM) or equivalent system.

For the avoidance of doubt, the components of the Available Corporate Liquidity calculation that are derived from financial statements shall be based on the financial statements of the Designated FCM Participant unless it provides an Affiliate guaranty in compliance with this Section VII.A, in which case the values shall be based on the financial statements of the entity(ies) providing the guaranty. If an acceptable Affiliate guaranty is provided, stop-loss and excess financial assurance values will still be based on the Designated FCM Participant.

Each Designated FCM Participant shall submit to the ISO, on a quarterly basis, its (or its guarantor's, as applicable) audited or unaudited balance sheet or equivalent financial statements, which shall show sufficient detail for the ISO to assess the Designated FCM Participant's (or guarantor's, as applicable) Available Corporate Liquidity. Such financial information shall be accompanied by a certificate from a Senior Officer of the Designated FCM Participant (or guarantor as applicable) that provides the relevant financial information and certifies the accuracy of the attached financial statements. If an attestation was made by an independent accounting firm, then the certificate shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required. The ISO shall post a generally acceptable "clean" form of certificate on its website. Financial statements provided on a quarterly basis shall be submitted within 10 days of such statements becoming available and within 65 days after the end of the applicable fiscal quarter.

Designated FCM Participants that are assessed as medium risk or high risk may elect to provide financial statements on a monthly basis until such a time as they are subsequently assessed as a lower risk category (e.g., from high risk to medium risk, medium risk to low risk, or high risk to low risk); provided that such election shall be for a minimum period of six continuous months during which they are continuously assessed at a lower risk category. Financial statements submitted on a monthly basis are required to be provided to the ISO within 20 days after the end of the prior month and otherwise be provided in accordance with this Section VII.A.

A Designated FCM Participant may choose not to submit financial statements as described in this Section VII.A. If a Designated FCM Participant chooses not to submit financial statements as described in this Section VII.A or if such financial statements are not compliant with the requirements described in this Section VII.A, the ISO shall use a value of $0.00 for Available Corporate Liquidity values derived from financial statements until such time as compliant financial statements are provided.

The ISO shall review the information provided pursuant to this Section VII.A on a rolling basis and will calculate the Available Corporate Liquidity within a reasonable time period which shall not exceed 30 Business Days from the date of receipt.

**3. FCM Affiliate Guaranties**

For the purposes of the Corporate Liquidity Assessment, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from an Affiliate to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant. Upon the ISO's acceptance of an Affiliate guaranty, the guarantor(s) must provide financial statements in accordance with this Section VII.A, and the Corporate Liquidity Assessment will be performed based on the financial information of the guarantor(s). The ISO will post a generally acceptable sample "clean" guaranty on its website, and all guaranties provided pursuant to this Section VII.A shall be in such form with only non-material changes (as determined by the ISO in its sole discretion). The ISO in its sole discretion may update the form guaranty from time to time. The ISO has the right to draw upon the guaranty in the event of a default under the ISO New England Billing Policy up to any amount owed for unpaid Capacity Performance Payments. At any time, the ISO may in its sole discretion provide notice to a Designated FCM Participant that it is choosing to reject or terminate its Affiliate guaranty because such guaranty presents unreasonable risk to the ISO or the New England Markets. In the case of a termination (or planned termination), upon the ISO providing such notice the guaranty shall not be considered for purposes of such Designated FCM Participant's Corporate Liquidity Assessment beginning at 8:30 a.m. on the next Business Day, provided that the ISO may, in its sole discretion, extend this period by up to twenty (20) Business Days. For the avoidance of doubt, notice from the ISO to the Designated FCM Participant that the guaranty its Affiliate provided is being terminated (or will be

terminated), does not constitute a termination notice under such guaranty and the ISO, in its sole discretion, may choose when to send the applicable termination notice under the terms of such guaranty.

In the ISO's sole discretion, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from multiple Affiliates to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant, so long as such guaranty is otherwise in accordance with this Section VII.A and the guarantors have joint and several liability under such guaranty.

**B. Non-Commercial Capacity**

Notwithstanding any provision of this Section VII to the contrary, a Designated FCM Participant offering Non-Commercial Capacity for a Resource that elected existing Resource treatment for the Capacity Commitment Period beginning June 1, 2010 will not be subject to the provisions of this Section VII.B with respect to that Resource (other than financial assurance obligations relating to transfers of Capacity Supply Obligations).

**1. FCM Deposit**

A Designated FCM Participant offering Non-Commercial Capacity into any upcoming Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day after its qualification for such auction under Market Rule 1, an amount equal to $2/kW times the Non-Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant (the "FCM Deposit").

**2. Non-Commercial Capacity in Forward Capacity Auctions**

**a. [Reserved for Future Use]**

**b. Non-Commercial Capacity Participating in Forward Capacity Auctions**

A Designated FCM Participant offering Non-Commercial Capacity into the Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8

a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction an amount calculated according to the following formula:

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) – FCM Deposit

Where:
NCC = the amount of Qualified Capacity that the ISO has qualified for the Designated FCM Participant for the Forward Capacity Auction minus any Commercial Capacity

NCCFCA$ = the Net CONE associated with the Forward Capacity Auction for which the NCC has qualified (adjusted as described in Section III.13.2.4).

Multiplier = one if the auction occurs within 40 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; two if the auction occurs within 28 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; and three if the auction begins within 16 months of the commencement of the Capacity Commitment Period for which the NCC has qualified.

FCM Deposit = $2/kW times the Non Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant

Upon completion of the Forward Capacity Auction, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated according to the following formula:

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) + NCC Trading FA

Where:
NCC = the Capacity Supply Obligation awarded to the Designated FCM Participant in the Forward Capacity Auction minus any Commercial Capacity

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the thirteenth Forward Capacity Auction, NCCFCA$ = the Capacity Clearing Price from the first run of the auction-clearing process of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded. For Capacity Supply Obligations acquired in the fourteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCCFCA$ = the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4).

Multiplier = one beginning at 8 a.m. (Eastern Time) on the first Business Day occurring within 40 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded; two beginning at 8 a.m. (Eastern Time) on the first Business Day occurring within 28 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded; and three beginning at 8 a.m. (Eastern Time) on the first Business Day occurring within 16 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded.

In the case of Non-Commercial Capacity that fails to become commercial by the commencement of the Capacity Commitment Period associated with the Forward Capacity Auction in which it was awarded a Capacity Supply Obligation, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated as follows: beginning at 8 a.m. (Eastern Time) on the first Business Day of the second month of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, the Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall be four. The Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall increase by one every six months thereafter until the Non-Commercial Capacity becomes commercial or the Capacity Supply Obligation is terminated.

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the twelfth Forward Capacity Auction, NCC Trading FA = zero. For Capacity Supply Obligations acquired in the thirteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCC Trading FA shall be zero until the start of the

applicable Capacity Commitment Period, at which time NCC Trading FA shall be calculated as described below, except that in no case shall NCC Trading FA be less than zero:

(a) the total amount of NCC that has been shed (whether before or after the start of the Capacity Commitment Period) in any reconfiguration auctions or Capacity Supply Obligation Bilaterals or that is subject to a failure to cover charge pursuant to Section III.13.3.4(b) (but this total amount shall not be greater than NCC); multiplied by

(b) the difference between: (x) the weighted average price at which the Capacity Supply Obligation was acquired in the Forward Capacity Auction (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); and (y) the weighted average price or failure to cover charge rate at which the Capacity Supply Obligation was shed or assessed, as applicable, except that for monthly Capacity Supply Obligation Bilaterals, one of the following prices will be used:

(i) If the Designated FCM Participant does not certify to the ISO that it has not entered into any contract or other transaction with another party regarding the pricing of such Capacity Supply Obligation Bilateral (other than those to be settled by the ISO) that has the effect of deflating its NCC Trading FA, then the lower of: (1) the applicable monthly reconfiguration auction price, and (2) the Capacity Supply Obligation Bilateral price shall be used;

(ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the lower of: (1) the Capacity Supply Obligation Bilateral price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs) shall be used; or

(iii) If neither subsection (i) nor (ii) applies, then the Capacity Supply Obligation Bilateral price shall be used.

plus

(c) the quantity of any Annual Reconfiguration Transactions associated with NCC for the relevant Capacity Commitment Period in which the Designated

FCM Participant is the Capacity Transferring Resource (but this amount shall not be greater than NCC) multiplied by the difference between: (x) the applicable annual reconfiguration auction clearing price, and (y) the transaction price, which shall equal one of the following:

(i) If the Designated FCM Participant does not certify to the ISO that it has not entered into any contract or other transaction with another party regarding the pricing of such Annual Reconfiguration Transaction (other than those to be settled by the ISO) that has the effect of deflating its NCC Trading FA, the transaction price shall be equal to the lower of: (1) the applicable annual reconfiguration auction clearing price, and (2) the applicable Annual Reconfiguration Transaction price;

(ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the transaction price shall be equal to the lower of: (1) the applicable Annual Reconfiguration Transaction price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); or

(iii) If neither subsection (i) nor (ii) applies, then the applicable Annual Reconfiguration Transaction price shall be used.

**c. Non-Commercial Capacity Deferral**

Where the Commission approves a request to defer a Capacity Supply Obligation filed pursuant to Section III.13.3.7 of Market Rule 1, the Designated FCM Participant must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) 30 days after Commission approval of the request to defer, an amount equal to the amount that would apply to a resource that has not achieved commercial operation one year after the start of a Capacity Commitment Period in which it has a Capacity Supply Obligation, as calculated pursuant to Section VII.B.2.a or Section VII.B.2.b, as applicable.

**3. Return of Non-Commercial Capacity Financial Assurance**

Non-Commercial Capacity cleared in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction that is declared commercial and has had its capacity rating verified by the ISO or otherwise becomes a Resource meeting the definition of Commercial Capacity, or that is declared commercial and had a part of its capacity rating verified by the ISO and the applicable Designated FCM Participant indicates no additional portions of that Resource will become commercial, that portion of the Resource shall no longer be considered Non-Commercial Capacity under the ISO New England Financial Assurance Policy and will instead become subject to the provisions of the ISO New England Financial Assurance Policy relating to Commercial Capacity; provided that in either such case, the Designated FCM Participant will need to include in the calculation of its Financial Assurance Requirement an amount attributable to any remaining Non-Commercial Capacity.

Once Non-Commercial Capacity associated with a Capacity Supply Obligation awarded in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter becomes commercial, the Non-Commercial Capacity Financial Assurance Amount for any remaining Non-Commercial Capacity shall be recalculated according to the process outlined above for Non-Commercial Capacity participating in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter.

**4. Credit Test Percentage Consequences for Provisional Members**

If a Provisional Member is required to provide additional financial assurance under the ISO New England Financial Assurance Policy solely in connection with (A) a supply offer of Non-Commercial Capacity into any Forward Capacity Auction and (B) its obligation to pay Participant Expenses as a Provisional Member, and that Provisional Member is maintaining the amount of additional financial assurance required under the ISO New England Financial Assurance Policy, then the provisions of Section III.B of the ISO New England Financial Assurance Policy relating to the consequences of that Market Participant's Market Credit Test Percentage equaling 80 percent (80%) or 90 percent (90%) shall not apply to that Provisional Member.

**C. [Reserved for Future Use]**

**D. Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance**

If a Designated FCM Participant that has acquired Capacity Supply Obligations associated with Non-Commercial Capacity is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy and does not cure such default within the appropriate cure period, or if a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy during the period between the day that is three Business Days before the FCM Deposit is required and the first day of the Forward Capacity Auction and does not cure such default within the appropriate cure period, then: (i) beginning with the first Business Day following the end of such cure period that Designated FCM Participant will be assessed a default charge of one percent (1%) of its total Non-Commercial Capacity Financial Assurance Amount at that time for each Business Day that elapses until it cures its default; and (ii) if such default is not cured by 5:00 p.m. (Eastern Time) on the sooner of (x) the fifth Business Day following the end of such cure period or (y) the second Business Day prior to the start of the next scheduled Forward Capacity Auction or annual reconfiguration auction or annual Capacity Supply Obligation Bilateral submission (such period being referred to herein as the "Non-Commercial Capacity Cure Period"), then, in addition to the other actions described in this Section VII, (A) all Capacity Supply Obligations associated with Non-Commercial Capacity that were awarded to the defaulting Designated FCM Participant in previous Forward Capacity Auctions and reconfiguration auctions and that the defaulting Designated FCM Participant acquired by entering into Capacity Supply Obligation Bilaterals shall be terminated; (B) the defaulting Designated FCM Participant shall be precluded from acquiring any Capacity Supply Obligation that would be associated with Non-Commercial Capacity for which the defaulting Designated FCM Participant has submitted an FCM Deposit; (C) the ISO will (1) draw down the entire amount of the FCM Deposit and the Non-Commercial Capacity Financial Assurance Amount associated with the terminated Capacity Supply Obligations and (2) issue an Invoice to the Designated FCM Participant if there is a shortfall resulting from that Designated FCM Participant's failure to maintain adequate financial assurance hereunder or if the Designated FCM Participant used a Market Credit Limit to meet its FCM Financial Assurance Requirements; and (D) the default charges described in clause (i) above shall not be assessed to that Designated FCM Participant. All default charges collected under clause (i) above will be deposited in the Late Payment Account in accordance with the ISO New England Billing Policy.

If a Designated FCM Participant's Capacity Supply Obligation is terminated under Market Rule 1, the ISO will draw down the entire Non-Commercial Capacity Financial Assurance Amount provided by such Designated FCM Participant with respect to such terminated Capacity Supply Obligation. If the Designated FCM Participant has not provided enough financial assurance to cover the amount due (or that would have been due but for the Designated FCM Participant's positive Market Credit Limit) with respect to such Non-Commercial Capacity Financial Assurance Amount, then the ISO will issue an Invoice to the Designated FCM Participant for the amount due.

**E. Composite FCM Transactions**

For separate resources that seek to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide that capacity (collectively, a "Composite FCM Transaction"), each Designated FCM Participant participating in that Composite FCM Transaction will be responsible for providing the financial assurance required as follows:

1. the FCM Financial Assurance Requirements for each Designated FCM Participant shall be determined solely with respect to the capacity being provided, or sought to be provided, by that Designated FCM Participant;

2. [reserved];

3. if the Composite FCM Transaction involves one or more Resources seeking to provide or providing Non-Commercial Capacity, the Non-Commercial Capacity Financial Assurance Amount under Section VII.B for each Designated FCM Participant with respect to that Composite FCM Transaction will be calculated based on the commercial status of the Non-Commercial Capacity cleared through the Forward Capacity Auction;

4. any Non-Commercial Capacity Financial Assurance Amount provided under Section VII.B by each Designated FCM Participant with respect to each Resource providing Non-Commercial Capacity in the Composite FCM Transaction will be recalculated according to Section VII.B.3 as the corresponding Resource becomes commercial; and

5. in the event that the Capacity Supply Obligation is terminated, Section VII.D shall apply only to the Non-Commercial Capacity of the Designated FCM Participant participating in the Composite FCM Transaction that has failed to satisfy its obligations, and any Invoice issued thereunder will be issued only to that Designated FCM Participant.

6. the FCM Delivery Financial Assurance calculated under Section VII.A for each Designated FCM Participant contributing resources to a Composite FCM Transaction shall be based on the Capacity Supply Obligation that is provided by that Designated FCM Participant in the current month of the Capacity Commitment Period, provided that the FCM charges incurred in previous months, but not yet paid, shall increase the FCM Financial Assurance Requirements only of the Designated FCM Participant that incurred the charges.

## F. Transfer of Capacity Supply Obligations

### 1. Transfer of Capacity Supply Obligations in Reconfiguration Auctions

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a reconfiguration auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of bidding in that reconfiguration auction, the amounts described in subsections (a) and (b) below.

(a) For the 12 month period beginning with the current month, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For purposes of this subsection (a), months in this period in which that Designated FCM Participant's net FCM revenue results in a credit are disregarded (i.e., the net credits from such months are not used to reduce the amount described in this subsection (a)) and the current month FCM charges are prorated to the proportion of remaining days in the month. The amount described in this subsection (a), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

(b) For the period including each month that is after the period described in subsection (a) above and that is included in a Capacity Commitment Period for which a Forward Capacity Auction has been conducted, the sum of that Designated FCM Participant's net

monthly FCM charges for each month in which the net FCM revenue results in a charge. For this period, the sum of such charges may be offset by net credits from months in which the net FCM revenue results in a credit, but in no case will the amount described in this subsection (b) be less than zero. The amount described in this subsection (b), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

For purposes of these calculations, the net FCM revenue for a month shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations, demand bids and Annual Reconfiguration Transactions in the Forward Capacity Market, exclusive of any accrued Capacity Performance Payments on positions currently or previously held. Upon the completion of each reconfiguration auction, the amount to be included in the calculation of any FCM Financial Assurance Requirements of that Designated FCM Participant shall be adjusted to reflect the cleared quantities at the zonal clearing price for all activity in that reconfiguration auction and accepted Annual Reconfiguration Transactions.

**2. Transfer of Capacity Supply Obligations in Capacity Supply Obligation Bilaterals**

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a Capacity Supply Obligation Bilateral must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Capacity Supply Obligation Bilateral, amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Capacity Supply Obligation Bilaterals, all of those transactions will be rejected. If the Designated FCM Participant's request to transfer a Capacity Supply Obligation in a Capacity Supply Obligation Bilateral is not accepted, it will no longer include amounts related to that Capacity Supply Obligation in the calculation of its FCM Financial Assurance Requirements.

**3. Financial Assurance for Annual Reconfiguration Transactions**

A Designated FCM Participant that submits an Annual Reconfiguration Transaction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Annual Reconfiguration Transaction, amounts calculated as described in Section

VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Annual Reconfiguration Transactions, all of those transactions will be rejected. If a transaction is rejected, the Designated FCM Participant is no longer required to include amounts related to that transaction in the calculation of its FCM Financial Assurance Requirements.

**4. Substitution Auctions**

A Designated FCM Participant that participates in a substitution auction must include the following charges and credits in its FCM Financial Assurance Requirements.

a. For any supply offer with at least one price-quantity pair priced less than zero must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing any price-quantity pairs priced less than zero for each month of the Capacity Commitment Period associated with the Forward Capacity Auction shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

b. A Designated FCM Participant (i) that submits a demand bid into a substitution auction for a resource that is subject to a multi-year rate pursuant to Section III.13.1.3.5.4 or Section III.13.1.1.2.2.4, (ii) for which the maximum charge that would result from clearing the capacity subject to the multi-year rate election would exceed the revenue the Designated FCM Participant will receive for the relevant Capacity Commitment Period under its multi-year rate election for the resource, (iii) must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing the capacity subject to the multi-year rate election shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity

Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

c. If a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction and does not cure such default by the earlier of (i) the end of the appropriate cure period and (ii) 5 p.m. (Eastern Time) on the second Business Day prior to the start of the Forward Capacity Auction, then the defaulting Designated FCM Participant shall be precluded from submitting a supply offer or demand bid that is subject to this Section VII.F.4.

d. Upon the completion of the substitution auction, the amount to be included in the calculation of the FCM Financial Assurance Requirements for a Designated FCM Participant as described in Section VII.F.1 above shall be adjusted to reflect all charges and credits related to the purchase or sale of Capacity Supply Obligations in the substitution auction.

## VIII. [Reserved]

## IX. THIRD-PARTY CREDIT PROTECTION

The ISO shall obtain third-party credit protection, in the form of credit insurance coverage ("Credit Coverage"), on terms acceptable to the ISO in its reasonable discretion at least in an amount covering collectively the Credit Qualifying Rated Market Participants based on the formula below. Notwithstanding the foregoing, if the entity providing such Credit Coverage cannot provide the amount required by this Section IX, the ISO will reduce the required coverage for all Credit Qualifying Rated Market Participants on a pro rata basis. The total amount of the Credit Coverage shall be at least the aggregate of the following formula; provided, however, if the entity providing the Credit Coverage denies coverage (in whole or in part) for any Credit Qualifying Rated Market Participant based on its rights under the insurance policy, the ISO will use reasonable efforts to obtain documentation regarding the denial and will make reasonable efforts to appeal such denial. For each Credit Qualifying Rated Market Participant, the portion of the Credit Coverage shall be the lesser of: (A) the sum of (x) 2.5 times the average Hourly Charges for such Credit Qualifying Rated Market Participant within the previous fifty-two calendar weeks plus (y) 2.5 times the sum of the average Non-Hourly Charges (excluding charges or credits related to FTR transactions) and the average Transmission Charges for such Credit Qualifying

Rated Market Participant within the previous twelve calendar months; or (B) $50 million. For any Credit Qualifying Rated Market Participant, the applicable amount of the Credit Coverage shall be adjusted monthly if the above formula produces a change that is either (A) 10% or greater, or (B) greater than $100,000. The Credit Coverage shall be provided by an insurance company rated "A-" or better by A.M. Best & Co. or "A" or better by S&P. The cost of the Credit Coverage obtained for each calendar year shall be allocated to all Credit Qualifying Rated Market Participants pro rata based, for each Credit Qualifying Rated Market Participant, on the average amount of the Invoices issued to that Credit Qualifying Rated Market Participant under the ISO New England Billing Policy in the preceding calendar year. Each Credit Qualifying Rated Market Participant shall provide the ISO with such information as may be reasonably necessary for the ISO to obtain the Credit Coverage at the lowest possible cost.

## X. ACCEPTABLE FORMS OF FINANCIAL ASSURANCE

Provided that the requirements set forth herein are satisfied, acceptable forms of financial assurance include shares of registered or private mutual funds held in a shareholder account or a letter of credit, each in accordance with the provisions of this Section X. All costs associated with obtaining financial security and meeting the provisions of the ISO New England Financial Assurance Policy are the responsibility of the Market Participant or Non-Market Participant Transmission Customer providing that security (each a "Posting Entity").

### A. Shares of Registered or Private Mutual Funds in a Shareholder Account

Shares of registered or private mutual funds in a shareholder account are an acceptable form of financial assurance provided that the Posting Entity providing such collateral (i) completes all required documentation to open an account with the financial institution selected by the ISO, after consultation with the NEPOOL Budget and Finance Subcommittee, (ii) completes and executes a security agreement ("Security Agreement") in the form of Attachment 1 to the ISO New England Financial Assurance Policy (as may be modified pursuant to Section X.B.1) and is in compliance with the Security Agreement, and (iii) completes and executes a Control Agreement in the form posted on the ISO website (as may be modified pursuant to Section X.B.1) and is in compliance with the Control Agreement. Any material variation from the form of Security Agreement included in Attachment 1 to the ISO New England Financial Assurance Policy (other than as modified pursuant to Section X.B.1) or the form of Control Agreement (other than as modified pursuant to Section X.B.1) posted on the ISO website must be approved by the ISO after consultation with the NEPOOL Budget and Finance

Subcommittee and, in the case of the Security Agreement, filed with the Commission. To the extent any amount of shares contained in the shareholder account is no longer required hereunder, the ISO shall return such collateral to the Posting Entity providing it within four (4) Business Days of a request to do so.

If the amount of collateral maintained in the shareholder account is below the required level (including by reason of losses on investments), the Posting Entity shall immediately replenish or increase the amount to the required level. The collateral will be held in an account maintained in the name of the Posting Entity and invested in the investment selected by that Posting Entity from a menu of investment options listed at the time on the ISO's website, which menu will be approved by the NEPOOL Budget and Finance Subcommittee, with discounts applied to the investments in certain of such options if and as determined by the NEPOOL Budget and Finance Subcommittee. If a Posting Entity does not select an investment for its collateral, that collateral will be invested in the "default" investment option selected by the ISO and approved by the NEPOOL Budget and Finance Subcommittee from time to time. Any dividends and distribution on such investment will accrue to the benefit of the Posting Entity. The ISO may sell or otherwise liquidate such investments at its discretion to meet the Posting Entity's obligations to the ISO. In no event will the ISO or NEPOOL or any NEPOOL Participant have any liability with respect to the investment of collateral under this Section X.A.

Notwithstanding the foregoing, an investment in shares of a registered fund in a shareholder account shall not be an acceptable form of financial assurance for a Posting Entity that is not a U.S. Person, as defined in Regulation S under the Securities Act of 1933, as amended, unless the financial institution selected by the ISO allows such Posting Entity to invest in the investment options listed at the time on the ISO's website or the Posting Entity is invested in the investment options listed on the ISO's website as of March 19, 2015.

**B. Letter of Credit**

An irrevocable standby letter of credit provides an acceptable form of financial assurance to the ISO. For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the end of the Business Day that is 30 days prior to the

termination of such letter of credit. If the letter of credit amount is below the required level, the Posting Entity shall immediately replenish or increase the letter of credit amount or obtain a substitute letter of credit. The account party on a letter of credit must be either the Posting Entity whose obligations are secured by that letter of credit or an Affiliate of that Posting Entity.

**1. Risk Mitigation Draws**

The ISO may draw against a letter of credit for two reasons in addition to a failure to pay under the ISO New England Billing Policy: i) an expiring letter of credit has not been renewed, or ii) the issuing bank is downgraded below the minimum ratings requirement, each in accordance with the terms of the letter of credit (the "Risk Mitigation Draws"). The ISO may exercise its rights under the Risk Mitigation Draws up to the amount that a Posting Entity's financial assurance requirements are not covered by acceptable forms of financial assurance. The ISO will hold such funds as a security deposit for the satisfaction of all obligations owed to the ISO by the Posting Entity (the "Risk Mitigation Drawn Funds"). The Risk Mitigation Drawn Funds shall be considered an appropriate form of financial assurance as described in this Section X. The ISO will hold all right, title, and interest in the Risk Mitigation Drawn Funds and the Posting Entity shall have a contingent right to such funds less any amounts applied to any debts owed to the ISO (pursuant to the Tariff, including the ISO New England Billing Policy): (i) upon the termination of its Market Participant Financial Assurance Requirement in accordance with Section III of the Financial Assurance Policy, (ii) upon the Posting Entity's provision of an alternative form of acceptable financial assurance in accordance with this Section X, or (iii) to the extent that any portion of the Risk Mitigation Drawn Funds are no longer required hereunder, upon the Posting Entity providing a written request to the ISO to return such portion of the funds (which request shall be honored within four (4) Business Days).

Upon request of the ISO, but no later than five (5) Business Days after the Risk Mitigation Draw, the Posting Entity shall execute a Security Agreement in the form of Attachment 1 to the ISO New England Financial Assurance Policy, provided that such form shall be modified to include within the definition of Collateral, funds received from a Risk Mitigation Draw, or an amendment to its existing Security Agreement in a form acceptable to the ISO in its sole discretion. Within thirty (30) days of the Risk Mitigation

Draw the Posting Entity shall satisfy its obligations pursuant to the paragraph immediately below to direct the deposit of the Risk Mitigation Drawn Funds into the Posting Entity's shareholder account as described in Section X.A. Notwithstanding the prior sentence, if the Posting Entity provides written documentation to the ISO (which documentation must be to the ISO's reasonable satisfaction) of its inability to open a shareholder account as described in Section X.A, and the Posting Entity has executed a Security Agreement or an amendment to its existing Security Agreement as required above, the ISO shall continue to hold the Risk Mitigation Drawn Funds (and such amount shall continue to be considered financial assurance), subject to the Posting Entity's contingent right to such funds as described above, in a form determined by the ISO in its sole discretion, and any interest or income accrued on such funds, if applicable, shall be considered part of the Posting Entity's financial assurance.

Upon a Risk Mitigation Draw and unless the Posting Entity has either posted other appropriate financial assurance in the forms permitted by this Section X or provided written documentation of its inability to do so in accordance with the preceding paragraph, the Posting Entity shall within thirty (30) days of the Risk Mitigation Draw complete any steps required by the ISO to (a) open a shareholder account as described in Section X.A, (b) execute any necessary documentation, including any amendments to the Security Agreement and Control Agreement deemed necessary by the ISO in a form acceptable to the ISO in its sole discretion, for the ISO to deposit the Risk Mitigation Drawn Funds into the Posting Entity's shareholder account, and (c) direct the ISO to deposit the Risk Mitigation Default Drawn Funds into that Posting Entity's shareholder account as described in Section X.A. Upon the Posting Entity's completion of the foregoing steps in (a) through (c) to the ISO's satisfaction, ISO shall deposit the Risk Mitigation Default Drawn Funds into that Posting Entity's shareholder account and the balance of the funds then on deposit in such account shall continue to be the collateral of the ISO.

The ISO may apply any funds received from a letter of credit, including the Risk Mitigation Drawn Funds held as a security deposit, to amounts owed by the Posting Entity in accordance with the ISO New England Billing Policy. If a Posting Entity fails to comply with the provisions of this Section X.B.1, then the Posting Entity will be

suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

**2. Requirements for Banks**

Each bank issuing a letter of credit that serves as financial assurance must meet the requirements of this Section X.B.2. Each such bank must be on the ISO's "List of Eligible Letter of Credit Issuers" which shall be established pursuant to this Section X.B.2. The ISO will post the current List of Eligible Letter of Credit Issuers on its website, and update that List and posting no less frequently than quarterly; provided that if a change is made to the List of Eligible Letter of Credit Issuers, the ISO shall update the List and provide notice to the NEPOOL Budget & Finance Subcommittee. To be included on the List of Eligible Letter of Credit Issuers, (i) the bank must be organized under the laws of the United States or any state thereof, or be the United States branch of a foreign bank; (ii) have a minimum long-term debt rating (or, if the bank does not have a minimum long-term debt rating, than a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's, or "A-" by Fitch; and (iii) be approved by the ISO in its sole discretion. In the event that a bank is rated by multiple Rating Agencies, if any applicable rating from the Rating Agencies falls below the levels listed, then a bank will not be considered to have satisfied the requirement under this paragraph. In addition, no Posting Entity may provide a letter of credit that has been issued by a bank that is an Affiliate of that Market Participant.

If a bank that is included on the List of Eligible Letter of Credit Issuers fails to satisfy the criteria set forth above or if the ISO determines in its sole discretion that despite satisfying the criteria set forth above, accepting a letter of credit from a bank on the List of Eligible Letter of Credit Issuers presents an unreasonable risk that a bank may fail to honor the terms of such letter of credit, the applicable Posting Entity will have five (5) Business Days from the date on which the ISO provides notice of such failure or removal to replace the letter of credit with a letter of credit from a bank satisfying the criteria or provide other financial assurance satisfying the requirements of the ISO New England Financial Assurance Policy. The ISO may extend that cure period to twenty (20) Business Days in its sole discretion. The ISO must promptly advise the NEPOOL Budget and Finance Subcommittee of any extension of a cure period beyond five (5) Business Days under this provision. For purposes of the ISO New England Financial

Assurance Policy, the letter of credit shall be valued at $0 at the expiration of the five (5) or twenty (20) Business Day cure period, as applicable.

No letter of credit bank may issue letters of credit under the ISO New England Financial Assurance Policy in an amount exceeding either: (i) $100 million in the aggregate for any single Posting Entity; or (ii) $150 million in aggregate for a group of Posting Entities that are Affiliates. If a bank is removed from the List of Eligible Letter of Credit Issuers based on the ISO's determination that there is an unreasonable risk that a bank may fail to honor the terms of such letter of credit, the ISO in its sole discretion may reinstate eligibility, provided that the bank otherwise meets the conditions of this Section X.B.2.

The following provisions shall apply when a bank fails to honor the terms of one or more letters of credit issued by the bank in favor of the ISO: (i) if the bank fails to honor the terms of one letter of credit in a rolling seven hundred and thirty day period, then the ISO will issue a notice of such failure to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contracts for all Market Participants; (ii) if the bank fails to honor either the terms of one letter of credit twice or the terms of two letters of credit in a rolling seven hundred and thirty day period, then (A) the ISO shall issue a notice described in subsection (i) above, (B) the bank will no longer be eligible to issue letters of credit in favor of the ISO, (C) any letters of credit issued by such bank in favor of the ISO will not be renewed, and (D) any letters of credit issued by such bank in favor of the ISO must be replaced with another acceptable form of financial assurance within five (5) Business Days from the date on which the ISO provides notice of such failure (the ISO may extend that cure period to twenty (20) Business Days in its sole discretion). For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the expiration of the five (5) or twenty (20) Business Day cure period, as applicable. Notwithstanding the foregoing, the ISO in its sole discretion may reinstate eligibility after not less than two years from the loss of eligibility, provided that the bank otherwise meets the conditions of this Section X.B.2.

**3. Form of Letter of Credit**

Attachment 2 provides a generally acceptable sample "clean" letter of credit, and all letters of credit provided by Posting Entities shall be in this form (with only minor, non-material changes), unless a variation therefrom is approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and filed with the Commission. Notwithstanding the foregoing, Posting Entities that have provided a letter of credit in a form that was previously acceptable (e.g., under a prior version of Attachment 2) shall not be required to resubmit such letter of credit until the earlier of (a) the amendment or expiration of such letter of credit, in which case Posting Entity shall be required to provide a letter of credit in the form of Attachment 2, or (b) September 1, 2026. Any letter of credit provided for a new Posting Entity, for the purpose of covering the Initial Market Participant Financial Assurance Requirement, must have a minimum term of 120 days. All costs incurred by the ISO in collecting on a letter of credit provided under the ISO New England Financial Assurance Policy shall be paid, or reimbursed to the ISO, by the Posting Entity providing that letter of credit.

**C. Special Provisions for Provisional Members**

Notwithstanding any other provision of the ISO New England Financial Assurance Policy to the contrary, due to the temporary nature of a Market Participant's status as a Provisional Member and the relatively small amounts due from Provisional Members, any Provisional Member required to provide additional financial assurance under the ISO New England Financial Assurance Policy may only satisfy the portion of that requirement attributable to Participant Expenses under the RNA by providing collateral maintained in a shareholder account in accordance with Section X.A. Provisional Members will not have any other Non-Hourly Requirements under the ISO New England Financial Assurance Policy. If a Provisional Member uses a standing instruction to pay its Invoices pursuant to the ISO New England Billing Policy, in order to avoid a default and/or a Late Payment Charge, the total amount of collateral maintained in a shareholder account by that Provisional Member should be equal to the sum of (x) the Provisional Member's Financial Assurance Requirement under the ISO New England Financial Assurance Policy that is attributable to Participant Expenses under the RNA and (y) the amount due from that Provisional Member on its next Invoice under that ISO New England Billing Policy (not including the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Provisional Member). Provisional Members are also required to satisfy all other

provisions of the ISO New England Financial Assurance Policy, and any additional financial assurance required to be provided by a Provisional Member that is not attributable to Participant Expenses may be satisfied by providing an acceptable form of financial assurance in accordance with this Section X. Without limiting or reducing in any way the requirements of the ISO New England Financial Assurance Policy that apply to a Provisional Member, the amount of collateral maintained in a shareholder account initially provided by a Provisional Member that is attributable to Participant Expenses (including any amounts provided in connection with the standing instruction under the ISO New England Billing Policy described above) shall be at least $2,500, and each Provisional Member will replenish that collateral maintained in a shareholder account to at least that $2,500 level on December 31 of each year.

## XI. MISCELLANEOUS PROVISIONS

### A. Obligation to Report Material Adverse Changes

Each Market Participant and each Non-Market Participant Transmission Customer is responsible for informing the ISO in writing within five (5) Business Days of any Material Adverse Change in its financial status. A "Material Adverse Change" in financial status includes, but is not limited to, the following: 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 Principals imposed 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; the filing of a material lawsuit that could materially adversely impact current or future financial results; or a significant change in the Market Participant's or Non-Market Participant Transmission Customer's market capitalization. A Market Participant's or Non-Market Participant Transmission Customer's failure to timely disclose a Material Adverse Change in its financial status may result in termination proceedings by the ISO. If the ISO determines that there is a Material Adverse Change in the financial condition

of a Market Participant- or Non-Market Participant Transmission Customer, then the ISO shall provide to that Market Participant or Non-Market Participant Transmission Customer a signed written notice two Business Days before taking any of the actions described below. The notice shall explain the reasons for the ISO's determination of the Material Adverse Change. After providing notice, the ISO may take one or more of the following actions: (i) require that, within two Business Days of receipt of the notice of Material Adverse Change, the Market Participant or Non-Market Participant Transmission Customer provide one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy and/or an additional amount of financial assurance in one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy; (ii) require that the Market Participant or Non-Market Participant Transmission Customer cease one or more transactions in the New England Markets; or (iii) require that the Market Participant or Non-Market Participant Transmission Customer take other measures to restore the ISO's confidence in its ability to safely transact in the New England Markets. Any additional amount of financial assurance required as a result of a Material Adverse Change shall be sufficient, as reasonably determined by the ISO, to cover the Market Participant's or Non-Market Participant Transmission Customer's potential settled and unsettled liability or obligation, provided, however, that if the additional amount of financial assurance required as a result of a Material Adverse Change is equal to or greater than $25 million, then the Chief Financial Officer shall first consult, to the extent practicable, with the ISO's Chief Executive Officer, Chief Operating Officer, and General Counsel. If the Market Participant or Non-Market Participant Transmission Customer fails to comply with any of the requirements imposed as a result of a Material Adverse Change, then the ISO may initiate termination proceedings against the Market Participant or Non-Market Participant Transmission Customer.

**B. Weekly Payments**

A Market Participant or Non-Market Participant Transmission Customer may request that, in lieu of providing the entire amount of one of the financial assurances set forth above to satisfy its Financial Assurance Requirement, a weekly billing schedule be implemented for its Non-Hourly Charges and its Transmission Charges. The ISO may, in its discretion, agree to such a request; provided, however, that any weekly billing arrangement for Non-Hourly Charges and Transmission Charges will terminate no more

than six (6) months after the date on which such arrangement begins unless the Market Participant or Non-Market Participant Transmission Customer requests an extension of such arrangement and demonstrates to the ISO's satisfaction in its sole discretion that the termination of such arrangement and compliance with the other provisions of the ISO New England Financial Assurance Policy (including providing the full amount of its Financial Assurance Requirement) will impose a substantial hardship on the Market Participant or Non-Market Participant Transmission Customer. Such demonstration of a substantial hardship shall be made every six (6) months after the initial demonstration, and a Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement for Non-Hourly Charges and Transmission Charges will be terminated if it fails to demonstrate to the ISO's satisfaction in its sole discretion at any such six (6) month interval that compliance with the other provisions of the ISO New England Financial Assurance Policy will impose a substantial hardship on it. If the ISO agrees to implement a weekly billing schedule for Non-Hourly Charges and Transmission Charges for a Market Participant or Non-Market Participant Transmission Customer, the Market Participant or Non-Market Participant Transmission Customer shall be billed weekly for such Non-Hourly Charges and Transmission Charges in accordance with the ISO New England Billing Policy. The Market Participant or Non-Market Participant Transmission Customer shall pay with respect to each weekly Invoice for Non-Hourly Charges and Transmission Charges an administrative fee, determined by the ISO, to reimburse the ISO for the costs it incurs as a result of that Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement.

If a weekly billing schedule is implemented for a Market Participant's or Non-Market Participant Transmission Customer's Non-Hourly Charges and Transmission Charges under this Section XI.B, the Market Participant or Non-Market Participant Transmission Customer may be required to provide the full amount of its Financial Assurance Requirement at any time if the Market Participant or Non-Market Participant Transmission Customer fails to pay when due any weekly Invoice. In addition, upon the termination of a Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement for Non-Hourly Charges and Transmission Charges, the Market Participant or Non-Market Participant Transmission Customer shall either satisfy the applicable rating requirements set forth herein, satisfy the Credit

Threshold, or provide the full amount of one of the other forms of financial assurance set forth herein.

**C. Use of Transaction Setoffs**

In the event that a Market Participant or Non-Market Participant Transmission Customer has failed to satisfy its Financial Assurance Requirement hereunder, the ISO may retain payments due to such Market Participant or Non-Market Participant Transmission Customer, up to the amount of such Market Participant's or Non-Market Participant Transmission Customer's unsatisfied Financial Assurance Requirement, as a cash deposit securing such Market Participant's or Non-Market Participant Transmission Customer's obligations to the ISO, NEPOOL, the Market Participants, the PTOs and the Non-Market Participant Transmission Customers, provided, however, that a Market Participant or Non-Market Participant Transmission Customer will not be deemed to have satisfied its Financial Assurance Requirement under the ISO New England Financial Assurance Policy because the ISO is retaining amounts due to it hereunder unless such Market Participant or Non-Market Participant Transmission Customer has satisfied all of the requirements of Section X with respect to such amounts.

**D. Reimbursement of Costs**

Each Market Participant or Non-Market Participant Transmission Customer that fails to perform any of its obligations under the Tariff, including without limitation those arising under the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, shall reimburse the ISO, NEPOOL and each Market Participant, PTO and Non-Market Participant Transmission Customer for all of the fees, costs and expenses that they incur as a result of such failure.

**E. Notification of Default**

In the event that a Market Participant or Non-Market Participant Transmission Customer fails to comply with the ISO New England Financial Assurance Policy (a "Financial Assurance Default"), such failure continues for at least two days and notice of that failure has not previously been given, the ISO may (but shall not be required to) notify such Market Participant or Non-Market Participant Transmission Customer in writing, electronically and by first class mail sent in each case to such Market Participant's or Non-Market Participant Transmission Customer's billing and credit contacts or such

Market Participant's member or alternate member on the Participants Committee (it being understood that the ISO will use reasonable efforts to contact all three where applicable), of such Financial Assurance Default. Either simultaneously with the giving of the notice described in the preceding sentence or within two days thereafter (unless the Financial Assurance Default is cured during such period), the ISO shall notify each other member and alternate on the Participants Committee and each Market Participant's and Non-Market Participant Transmission Customer's billing and credit contacts of the identity of the Market Participant or Non-Market Participant Transmission Customer receiving such notice, whether such notice relates to a Financial Assurance Default, and the actions the ISO plans to take and/or has taken in response to such Financial Assurance Default. In addition to the notices provided for herein, the ISO will provide any additional information required under the ISO New England Information Policy.

**F. Remedies Not Exclusive**

No remedy for a Financial Assurance Default is or shall be deemed to be exclusive of any other available remedy or remedies. Each such remedy shall be distinct, separate and cumulative, shall not be deemed inconsistent with or in exclusion of any other available remedy, and shall be in addition to and separate and distinct from every other remedy. A Financial Assurance Default may result in suspension of the Market Participant or Non-Market Participant Transmission Customer or the commencement of termination proceedings by the ISO.

**G. Inquiries and Contests**

A Market Participant or Non-Market Participant Transmission Customer may request a written explanation of the ISO's determination of its Market Credit Limit, Transmission Credit Limit, Financial Assurance Requirement or Transmission Obligations, including any change thereto, by submitting that request in writing to the ISO's Credit Department, either by email at CreditDepartment@iso-ne.com or by facsimile at (413) 540-4569. That request must include the Market Participant's customer identification number, the name of the Market Participant or Non-Market Participant Transmission Customer and the specific information for which the Market Participant or Non-Market Participant Transmission Customer would like an explanation and must be submitted by the designated credit contact for that Market Participant or Non-Market Participant Transmission Customer as on file with the ISO. In addition, since Financial Assurance

Requirements are updated at least daily, any request for an explanation relating to the calculation of, or a change in, a Financial Assurance Requirement must be submitted on the same day as that calculation or change. The ISO's response to any request under this Section XI.G shall include an explanation of how the applicable calculation or determination was performed using the formulas and criteria in the ISO New England Financial Assurance Policy. A Market Participant or Non-Market Participant Transmission Customer may contest any calculation or determination by the ISO under the ISO New England Financial Assurance Policy using the dispute resolution provisions of Section I.6 of the Tariff.

**H. Forward Contract/Swap Agreement**

All FTR transactions constitute "forward contracts" and/or "swap agreements" within the meaning of the United States Bankruptcy Code (the "Bankruptcy Code"), and the ISO shall be deemed to be a "forward contract merchant" and/or "swap participant" within the meaning of the Bankruptcy Code for purposes of those FTR transactions. Pursuant to the ISO New England Financial Assurance Policy, the ISO Tariff and the Market Participant Service Agreement with each Market Participant, the ISO already has, and shall continue to have, the following rights (among other rights) in respect of a Market Participant default under those documents (including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy): A) the right to terminate and/or liquidate any FTR transaction held by that Market Participant; B) the right to immediately proceed against any additional financial assurance provided by that Market Participant; C) the right to set off any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement or similar agreement against any amounts due and owing by that Market Participant pursuant to any forward contract, swap agreement or similar agreement, such arrangement to constitute a "master netting agreement" within the meaning of the Bankruptcy Code; and D) the right to suspend that Market Participant from entering into future transactions in the FTR system. For the avoidance of doubt, upon the commencement of a voluntary or involuntary proceeding for a Market Participant under the Bankruptcy Code, and without limiting any other rights of the ISO or obligations of any Market Participant under the Tariff (including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy) or any Market Participant Service Agreement, the ISO may exercise any of its rights against such Market Participant, including, without limitation 1) the right to

terminate and/or liquidate any FTR transaction held by that Market Participant, 2) the right to immediately proceed against any additional financial assurance provided by that Market Participant, 3) the right to set off any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement and/or master netting agreement against any amounts due and owing by that Market Participant with respect to an FTR transaction including as a result of the actions taken by the ISO pursuant to 1) above, and 4) the right to suspend that Market Participant from entering into future transactions in the FTR system.

**ATTACHMENT 1**

**SECURITY AGREEMENT**

THIS SECURITY AGREEMENT (the "Security Agreement") is effective as of this [__] day of [_____], 20[_], by and between [INSERT NAME], a [_____], having its principal office and place of business at [_____] (the "Debtor"), and ISO New England Inc., a Delaware nonprofit corporation (the "Secured Party" and collectively with the Debtor, the "Parties").

WITNESSETH:

In consideration of the mutual promises and covenants herein contained, the Parties agree as follows:

1. Definitions.

a. In this Security Agreement:

i. "Code" shall mean the Uniform Commercial Code, as enacted in the State of Connecticut and as amended from time to time.

ii. "Collateral" shall mean (a) all cash provided, submitted, wired or otherwise transferred or deposited by the Debtor to or with the Secured Party or a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf, to hold or invest such cash deposit, from time to time in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (b) all securities or other investment property (as defined in the Code) of the Debtor, whether or not purchased with such cash deposit, submitted, wired or otherwise transferred, deposited or maintained by the Debtor to or with the Secured Party or its designee, in each case in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (c) all other property of Debtor submitted, pledged, assigned or otherwise transferred by the Debtor to the Secured Party or its designee, in each case, in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; and (d) the products and proceeds of each of the foregoing.

iii. "ISO Financial Assurance Policy" shall mean the Financial Assurance Policy in the Tariff, as amended, supplemented or restated from time to time, including but not limited to the Financial Assurance Policy in Exhibit 1A to Section I of the Tariff.

iv. "Tariff" shall mean the ISO New England Inc. Transmission, Markets and Services Tariff, as filed with the Federal Energy Regulatory Commission, as amended, supplemented and/or restated from time to time.

v. "Obligations" shall mean any and all amounts due from Debtor from time to time under the Tariff.

vi. "Market Participants" shall have the meaning set forth in the Tariff.

b. Any capitalized term not defined herein that is defined in the Code shall have the meaning as defined in the Code.

2. Security Interest. To secure the payment of all Obligations of the Debtor, Debtor hereby grants and conveys to the Secured Party a security interest in the Collateral. The Debtor hereby irrevocably authorizes the Secured Party at any time and from time to time to file in any applicable filing office any initial financing statements and amendments thereto that provide any information required by part 5 of Article 9 of the Code for the sufficiency or filing office acceptance of any financing statement or amendment.

3. Debtor's Covenants. The Debtor warrants, covenants and agrees with the Secured Party as follows:

a. The Debtor shall perform all of the Debtor's obligations under this Security Agreement according to its terms.

b. The Debtor shall defend the title to the Collateral against any and all persons and against all claims.

c. The Debtor shall at any time and from time to time take such steps as the Secured Party may reasonably request to ensure the continued perfection and priority of the Secured Party's security interest in the Collateral and the preservation of its rights therein.

d. The Debtor acknowledges and agrees that this Security Agreement grants, and is intended to grant, a security interest in the Collateral. If the Debtor is a corporation, limited liability company, limited partnership or other Registered Organization (as that term is defined in Article 9 of the Uniform Commercial Code as in effect in Connecticut) the Debtor shall, at its expense, furnish to Secured Party a certified copy of Debtor's organization documents verifying its correct legal name or, at Secured Party's election, shall permit the Secured Party to obtain such certified copy at Debtor's expense. From

time to time at Secured Party's election, the Secured Party may obtain a certified copy of Debtor's organization documents and a search of such Uniform Commercial Code filing offices, as it shall deem appropriate, at Debtor's expense, to verify Debtor's compliance with the terms of this Security Agreement.

e. The Debtor authorizes the Secured Party, if the Debtor fails to do so, to do all things required of the Debtor herein and charge all expenses incurred by the Secured Party to the Debtor together with interest thereon, which expenses and interest will be added to the Obligations.

4. Debtor's Representations and Warranties. The Debtor represents and warrants to the Secured Party as follows:

a. The exact legal name of the Debtor is as first stated above.

b. Except for the security interest of the Secured Party, Debtor is the owner of the Collateral free and clear of any encumbrance of any nature.

5. Non-Waiver. Waiver of or acquiescence in any default by the Debtor or failure of the Secured Party to insist upon strict performance by the Debtor of any warranties, covenants, or agreements in this Security Agreement shall not constitute a waiver of any subsequent or other default or failure. No failure to exercise or delay in exercising any right, power or remedy of the Secured Party under this Security Agreement shall operate as a waiver thereof, nor shall any partial exercise of any right, power or remedy preclude any other or further exercise thereof or the exercise of any other right, power or remedy. The failure of the Secured Party to insist upon the strict observance or performance of any provision of this Security Agreement shall not be construed as a waiver or relinquishment of such provision. The rights and remedies provided herein are cumulative and not exclusive of any other rights or remedies provided at law or in equity.

6. Events of Default. Any one of the following shall constitute an "Event of Default" hereunder by the Debtor:

a. Failure by the Debtor to comply with or perform any provision of this Security Agreement or to pay any Obligation; or

b. Any representation or warranty made or given by the Debtor in connection with this Security Agreement proves to be false or misleading in any material respect; or

c. Any part of the Collateral is attached, seized, subjected to a writ or distress warrant, or is levied upon, or comes within the possession of any receiver, trustee, custodian or assignee for the benefit of creditors.

7. Remedy upon the Occurrence of an Event of Default. Upon the occurrence of any Event of Default the Secured Party shall, immediately and without notice, be entitled to use, sell, or otherwise liquidate the Collateral to pay all Obligations owed by the Debtor.

8. Attorneys' Fees, etc. Upon the occurrence of any Event of Default, the Secured Party's reasonable attorneys' fees and the legal and other expenses for pursuing, receiving, taking, keeping, selling, and liquidating the Collateral and enforcing the Security Agreement shall be chargeable to the Debtor.

9. Other Rights.

a. In addition to all rights and remedies herein and otherwise available at law or in equity, upon the occurrence of an Event of Default, the Secured Party shall have such other rights and remedies as are set forth in the Tariff and ISO Financial Assurance Policy.

b. Notwithstanding the provisions of the ISO New England Information Policy, as amended, supplemented or restated from time to time (the "ISO New England Information Policy"), Debtor hereby (i) authorizes the Secured Party to disclose any information concerning Debtor to any court, agency or entity which is necessary or desirable, in the sole discretion of the Secured Party, to establish, maintain, perfect or secure the Secured Party's rights and interest in the Collateral (the "Debtor Information"); and (ii) waives any rights it may have under the ISO New England Information Policy to prevent, impair or limit the Secured Party from disclosing such information concerning the Debtor.

10. PRE-JUDGMENT REMEDY. DEBTOR ACKNOWLEDGES THAT THIS SECURITY AGREEMENT AND THE UNDERLYING TRANSACTIONS GIVING RISE HERETO CONSTITUTE COMMERCIAL BUSINESS TRANSACTED WITHIN THE STATE OF CONNECTICUT. IN THE EVENT OF ANY LEGAL ACTION BETWEEN DEBTOR AND

THE SECURED PARTY HEREUNDER, DEBTOR HEREBY EXPRESSLY WAIVES ANY RIGHTS WITH REGARD TO NOTICE, PRIOR HEARING AND ANY OTHER RIGHTS IT MAY HAVE UNDER THE CONNECTICUT GENERAL STATUTES, CHAPTER 903a, AS NOW CONSTITUTED OR HEREAFTER AMENDED, OR OTHER STATUTE OR STATUTES, STATE OR FEDERAL, AFFECTING PREJUDGMENT REMEDIES, AND THE SECURED PARTY MAY INVOKE ANY PREJUDGMENT REMEDY AVAILABLE TO IT, INCLUDING, BUT NOT LIMITED TO, GARNISHMENT, ATTACHMENT, FOREIGN ATTACHMENT AND REPLEVIN, WITH RESPECT TO ANY TANGIBLE OR INTANGIBLE PROPERTY (WHETHER REAL OR PERSONAL) OF DEBTOR TO ENFORCE THE PROVISIONS OF THIS SECURITY AGREEMENT, WITHOUT GIVING DEBTOR ANY NOTICE OR OPPORTUNITY FOR A HEARING.

11. WAIVER OF JURY TRIAL. THE DEBTOR AND THE SECURED PARTY HEREBY EACH KNOWINGLY, VOLUNTARILY AND IRREVOCABLY WAIVES THE RIGHT TO TRIAL BY JURY IN ANY ACTION, DEFENSE, COUNTERCLAIM, CROSSCLAIM AND/OR ANY FORM OF PROCEEDING BROUGHT IN CONNECTION WITH THIS SECURITY AGREEMENT OR RELATING TO ANY OBLIGATIONS SECURED HEREBY.

12. Additional Waivers. Demand, presentment, protest and notice of nonpayment are hereby waived by Debtor. Debtor also waives the benefit of all valuation, appraisement and exemption laws.

13. Binding Effect. The terms, warranties and agreements herein contained shall bind and inure to the benefit of the respective Parties hereto, and their respective legal representatives, successors and assigns.

14. Assignment. The Secured Party may, upon notice to the Debtor, assign without limitation its security interest in the Collateral.

15. Amendment. This Security Agreement may not be altered or amended except by an agreement in writing signed by the Parties.

16. Term.

a. This Security Agreement shall continue in full force and effect until all Obligations owed by the Debtor have been paid in full.

b. No termination of this Security Agreement shall in any way affect or impair the rights and liabilities of the Parties hereto relating to any transaction or events prior to such termination date, or to the Collateral in which the Secured Party has a security interest, and all agreements, warranties and representations of the Debtor shall survive such termination.

17. Choice of Law. The laws of the State of Connecticut shall govern the rights and duties of the Parties herein contained without giving effect to any conflict-of-law principles.

IN WITNESS WHEREOF, the Parties have signed and sealed this Security Agreement as of the day and year first above written.

[INSERT NAME]

By: _____

Name:

Title:

ISO NEW ENGLAND INC.

By:_____

Name:

Title:

**ATTACHMENT 2**

**SAMPLE STANDBY LETTER OF CREDIT**

[DATE PROVIDED]

IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO.

[EXPIRATION DATE]

WE DO HEREBY ISSUE THIS IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT BY ORDER OF AND FOR THE ACCOUNT OF [POSTING ENTITY OR AFFILIATE OF POSTING ENTITY ON BEHALF OF POSTING ENTITY] ("ACCOUNT PARTY") IN FAVOR OF ISO NEW ENGLAND INC. ("ISO" OR "BENEFICIARY") ("STANDBY LETTER OF CREDIT").

THIS STANDBY LETTER OF CREDIT IS IRREVOCABLE AND IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS AND BONA FIDE HOLDERS OF THIS STANDBY LETTER OF CREDIT THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT WILL BE HONORED ON PRESENTATION OF THIS STANDBY LETTER OF CREDIT.

THIS STANDBY LETTER OF CREDIT IS AVAILABLE IN ONE OR MORE DRAFTS AND MAY BE DRAWN HEREUNDER FOR THE ACCOUNT OF THE ACCOUNT PARTY UP TO AN AMOUNT NOT EXCEEDING US$ _____.00 (UNITED STATES DOLLARS _____ AND 00/100) .

THIS STANDBY LETTER OF CREDIT IS DRAWN AGAINST BY PRESENTATION TO US AT OUR OFFICE LOCATED AT THE FOLLOWING ADDRESS:

_____

_____

_____;

OF A DRAFT IN THE FORM OF A DRAWING CERTIFICATE THAT IS SIGNED BY A PURPORTED OFFICER OR AUTHORIZED AGENT OF THE ISO AND DATED THE DATE OF

PRESENTATION CONTAINING THE FOLLOWING STATEMENT IN (1) BELOW ALONG WITH THE APPROPRIATE STATEMENT IN (2) BELOW:

(1) "THE UNDERSIGNED HEREBY CERTIFIES TO [BANK] ("ISSUER"), WITH REFERENCE TO IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO. [------] (THE "STANDBY LETTER OF CREDIT") ISSUED BY ISSUER IN FAVOR OF ISO NEW ENGLAND INC. ("ISO"), THAT

(2) [POSTING ENTITY] HAS FAILED TO PAY THE ISO, IN ACCORDANCE WITH THE TERMS AND PROVISIONS OF THE TARIFF FILED BY THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____.];**OR**

[ISSUER HAS FAILED TO MAINTAIN A MINIMUM LONG-TERM DEBT RATING FROM ANY APPLICABLE RATING AGENCY (OR, IF THE ISSUER DOES NOT HAVE A MINIMUM LONG-TERM DEBT RATING, THEN A MINIMUM CORPORATE RATING) OF "A-" BY STANDARD AND POOR'S , OR "A3" BY MOODY'S OR "A-" BY FITCH, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____. **]; OR**

[**INCLUDE ONLY IN FORM IF LETTER OF CREDIT HAS A FIXED EXPIRATION DATE:]** [AS OF THE CLOSE OF BUSINESS ON _____, 20__ (FILL IN DATE WHICH IS WITHIN 30 DAYS BEFORE THE EXPIRATION DATE OF THE STANDBY LETTER OF CREDIT), [ACCOUNT PARTY] HAS FAILED TO RENEW THE STANDBY LETTER OF CREDIT IN A MANNER ACCEPTABLE TO THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____. **]; OR**

[**INCLUDE ONLY IN FORM IF LETTER OF CREDIT HAS AUTOMATIC RENEWAL LANGUAGE:]** [AS OF THE CLOSE OF BUSINESS ON _____, 20__ (FILL IN DATE WHICH IS WITHIN 30 DAYS BEFORE THE EXPIRATION DATE OF THE STANDBY LETTER OF CREDIT IF NOT AUTORENEWING), WE HAVE BEEN PROVIDED NOTICE FROM [ACCOUNT PARTY] [ISSUER] THAT THE STANDBY LETTER OF CREDIT WILL NOT BE

EXTENDED FOR AN ADDITIONAL ONE (1) YEAR PERIOD, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____.]

IF PRESENTATION OF ANY DRAWING CERTIFICATE IS MADE ON A BUSINESS DAY AND SUCH PRESENTATION IS MADE AT OUR COUNTERS ON OR BEFORE 10:00 A.M. _____ TIME, WE SHALL SATISFY SUCH DRAWING REQUEST ON THE SAME BUSINESS DAY. IF THE DRAWING CERTIFICATE IS RECEIVED AT OUR COUNTERS AFTER 10:00 A.M. _____ TIME, WE WILL SATISFY SUCH DRAWING REQUEST ON THE NEXT BUSINESS DAY. FOR THE PURPOSES OF THIS SECTION, A BUSINESS DAY MEANS A DAY, OTHER THAN A SATURDAY OR SUNDAY, ON WHICH THE FEDERAL RESERVE BANK OF NEW YORK IS NOT AUTHORIZED OR REQUIRED TO BE CLOSED. DISBURSEMENTS SHALL BE IN ACCORDANCE WITH THE INSTRUCTIONS OF THE ISO.

THE FOLLOWING TERMS AND CONDITIONS APPLY:

THIS STANDBY LETTER OF CREDIT SHALL EXPIRE AT THE CLOSE OF BUSINESS [DATE] [AT LEAST 120 DAYS AFTER ISSUANCE FOR NEW POSTING ENTITIES].

[**INCLUDE ONLY IF LETTER OF CREDIT HAS A FIXED EXPIRATION DATE:]** [IF [ACCOUNT PARTY] HAS FAILED TO RENEW THIS STANDBY LETTER OF CREDIT IN A MANNER ACCEPTABLE TO THE ISO, YOU MAY DRAW ON THIS STANDBY LETTER OF CREDIT WITHIN THE THIRTY (30) DAYS PRIOR TO THE EXPIRY DATE BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.]

[**INCLUDE ONLY IF LETTER OF CREDIT IS TO HAVE AUTOMATIC RENEWAL LANGUAGE:]** [IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT IT WILL BE AUTOMATICALLY EXTENDED WITHOUT AN AMENDMENT FOR A (1) YEAR PERIOD BEGINNING ON THE INITIAL EXPIRATION DATE HEREOF AND UPON EACH ANNIVERSARY OF SUCH DATE, UNLESS AT LEAST [THIRTY (30) **OR** SIXTY (60) **OR** NINETY (90)] DAYS PRIOR TO ANY SUCH EXPIRATION DATE WE HAVE SENT YOU, OR THE ACCOUNT PARTY HAS SENT YOU, WRITTEN NOTICE BY

REGULAR AND REGISTERED MAIL OR COURIER SERVICE THAT WE OR THE ACCOUNT PARTY ELECT NOT TO PERMIT THIS LETTER OF CREDIT TO BE SO EXTENDED, AND THAT THIS LETTER OF CREDIT WILL EXPIRE ON ITS THEN CURRENT EXPIRATION DATE. UPON RECEIPT OF SUCH NOTICE, YOU MAY DRAW ON THIS STANDBY LETTER OF CREDIT WITHIN THE THIRTY (30) DAYS PRIOR TO THE THEN RELEVANT EXPIRY DATE BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.]

IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT WE SHALL MAINTAIN A MINIMUM LONG-TERM DEBT RATING (OR, IF WE DO NOT HAVE A MINIMUM LONG-TERM DEBT RATING, THEN A MINIMUM CORPORATE RATING) OF "A-" BY STANDARD AND POOR'S, OR "A3" BY MOODY'S OR "A-" BY FITCH. IN THE EVENT THAT WE ARE RATED BY MULTIPLE RATING AGENCIES, IF ANY APPLICABLE RATING FROM THE RATING AGENCIES FALLS BELOW THE LEVELS LISTED, THEN WE SHALL NOT BE CONSIDERED TO HAVE SATISFIED THIS CONDITION. IN THE EVENT THAT WE DO NOT SATISFY THE CONDITION REQUIRED BY THIS PARAGRAPH, YOU MAY DEMAND PAYMENT FROM US AT THE ADDRESS ABOVE, BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.

THE AMOUNT WHICH MAY BE DRAWN BY YOU UNDER THIS STANDBY LETTER OF CREDIT SHALL BE AUTOMATICALLY REDUCED BY THE AMOUNT OF ANY DRAWINGS HEREUNDER AT OUR COUNTERS. ANY NUMBER OF PARTIAL DRAWINGS ARE PERMITTED FROM TIME TO TIME HEREUNDER.

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY.

THIS STANDBY LETTER OF CREDIT IS NOT TRANSFERABLE OR ASSIGNABLE. THIS STANDBY LETTER OF CREDIT DOES NOT INCORPORATE AND SHALL NOT BE DEEMED MODIFIED, AMENDED OR AMPLIFIED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE ISP, AS DEFINED BELOW) OR (B) IN WHICH THIS STANDBY

LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS STANDBY LETTER OF CREDIT RELATES.

THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE INTERNATIONAL STANDBY PRACTICES ("ISP98") OF THE INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 590, INCLUDING ANY AMENDMENTS, MODIFICATIONS, OR REVISIONS THEREOF (THE "ISP"), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ISP, IN WHICH CASE THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL GOVERN. THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY THE INTERNAL LAWS OF THE COMMONWEALTH OF MASSACHUSETTS TO THE EXTENT THAT THE TERMS ARE NOT GOVERNED BY THE ISP.

THIS STANDBY LETTER OF CREDIT MAY NOT BE AMENDED, CHANGED OR MODIFIED WITHOUT THE EXPRESS WRITTEN CONSENT OF THE ISO AND ISSUER.

WE HEREBY ENGAGE WITH YOU THAT DOCUMENTS DRAWN UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL BE DULY HONORED UPON PRESENTATION AS SPECIFIED AND WE REPRESENT THAT THE ACCOUNT PARTY IS NOT AN AFFILIATE OF THE ISSUER.

PRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS STANDBY LETTER OF CREDIT MAY BE SENT TO US BY COURIER, CERTIFIED MAIL, REGISTERED MAIL, OR FACSIMILE (WITH A CONFIRMING COPY OF SUCH FACSIMILE SENT AFTER THE DRAWING BY CERTIFIED MAIL TO THE ADDRESS SET FORTH BELOW; PROVIDED HOWEVER, THAT THE CONFIRMING COPY SHALL NOT BE A PREREQUISITE FOR US TO HONOR ANY PRESENTATION OTHERWISE MADE IN ACCORDANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT), OR SUCH OTHER ADDRESS AS MAY HEREAFTER BE FURNISHED BY US. OTHER NOTICES CONCERNING THIS STANDBY LETTER OF CREDIT MAY BE SENT BY SIMILAR COMMUNICATIONS FACILITY TO THE RESPECTIVE ADDRESSES SET FORTH BELOW. ALL SUCH NOTICES AND COMMUNICATIONS SHALL BE EFFECTIVE UPON RECEIPT BY THE INTENDED RECIPIENT PARTY.

IF TO THE BENEFICIARY OF THIS STANDBY LETTER OF CREDIT:

ISO NEW ENGLAND INC.
ATTENTION: CREDIT DEPARTMENT
1 SULLIVAN RD. HOLYOKE, MA 01040
FAX: 413-540-4569
EMAIL: CREDITDEPARTMENT@ISO-NE.COM

IF TO THE ACCOUNT PARTY:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

IF TO ISSUER:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

_____ _____

[SIGNATURE] [SIGNATURE]

**ATTACHMENT 3**

**ISO NEW ENGLAND MINIMUM CRITERIA FOR MARKET PARTICIPATION OFFICER CERTIFICATION FORM**

| **Certifying Entity:** | |
|---|---|

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the minimum criteria for market participation requirements set forth in Sections II.A.2 and II.A.3 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity has established or contracted for written policies, procedures, and controls applicable to participation in the New England Markets, approved by Certifying Entity's independent risk management function[1], which provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Certifying Entity is exposed, including, but not limited to, credit risk, liquidity risk, concentration risk, default risk, operation risk, and market risk.

2. Certifying Entity has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets.

3. Certifying Entity has appropriate operating procedures and technical abilities to promptly and effectively respond to all ISO New England communications and directions.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England's minimum criteria for market participation requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

_____
(Signature)

Print Name:_____

Title: _____

Date: _____

[1] As used in this certification, a Certifying Entity's "independent risk management function" can include appropriate corporate persons or bodies that are independent of the Certifying Entity's trading functions, such as a risk management committee, a risk officer, a Certifying Entity's board or board committee, or a board or committee of the Certifying Entity's parent company.

**ATTACHMENT 4**

**ISO NEW ENGLAND ADDITIONAL ELIGIBILITY REQUIREMENTS**

**CERTIFICATION FORM**

| **Certifying Entity:** | |
|---|---|

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the additional eligibility requirements set forth in Section II.A.5 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity is now and in good faith will seek to remain (check applicable box(es)):

   □ an "appropriate person," as defined in section(s) [ ] of the Commodity Exchange Act (7 U.S.C. § 1 *et seq*.) (specify which section(s) of Commodity Exchange Act sections 4(c)(3)(A) through (J) apply)) (if Certifying Entity is relying on section 4(c)(3)(F), it shall accompany this certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the Certifying Entity's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy);

   □ an "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or

   ☐ a "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

2. If at any time Certifying Entity no longer satisfies the criteria in paragraph 1 above, Certifying Entity will immediately notify ISO New England in writing and will immediately cease all participation in the New England Markets.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England's additional eligibility requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

_____

(Signature)

Print Name:_____

Title: _____

Date: _____

**ATTACHMENT 5**

**ISO NEW ENGLAND CERTIFICATE REGARDING CHANGES TO SUBMITTED RISK MANAGEMENT POLICIES FOR FTR PARTICIPATION**

| **Certifying Entity:** | |
|---|---|

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the annual certification requirement for FTR market participation regarding its risk management policies, procedures, and controls set forth in Section II.A.2(b) of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows (check applicable box):

1. □ There have been no changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity's participation in the FTR market.

   OR

2. □ There have been changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity's participation in the FTR market and such changes are clearly identified and attached hereto.*

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England's risk management policy requirements for FTR market participants and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

_____

____

(Signature)

Print Name:_____

Title:

_____

Date:

_____

_____

* As used in this certificate, "clearly identified" changes may include a redline comparing the current written risk management policies, procedures, and controls and the previously submitted written risk management policies, procedures, and controls; or resubmission of the written risk management policies, procedures, and controls with a bulleted list of all changes, including section and/or page numbers.

## ATTACHMENT 6

## MINIMUM CRITERIA FOR MARKET PARTICIPATION

## INFORMATION DISCLOSURE FORM

Date: _____

Prepared by: _____

Customer/Applicant:[1] _____

I, _____, a duly authorized Senior Officer of _____ ("Certifying Entity"), understanding that ISO New England Inc. ("ISO") is relying on this certification provided pursuant to Financial Assurance Policy Section II.A.1(a), hereby certify that I have full authority to bind Certifying Entity and further certify on behalf of Certifying Entity that the information contained herein is true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission:

1. List of all Principals.[2] Please discuss each Principal's relationship with the Certifying Entity and describe each Principal's previous experience related to participation in North American wholesale or retail energy markets or trading exchanges:

[1] Customer and Applicant are each defined in Section II.A of the ISO New England Financial Assurance Policy, Exhibit 1A to Section 1 of the ISO Transmission, Markets, and Services Tariff ("Tariff"). Capitalized terms used but not otherwise defined herein shall have the meaning given to them in the Tariff.

[2] 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 ("FERC"), the Securities and Exchange Commission ("SEC"), the Commodity Futures Trading Commission ("CFTC"), any exchange monitored by the National Futures Association ("NFA"), 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.

2. List all material litigation (criminal or civil) against Certifying Entity or any of the Certifying Entity's Principals, Personnel,[1] or Predecessors,[2] arising out of participation in any wholesale or retail energy market (domestic or international) or trading exchanges in the past ten (10) years:
*(Enter N/A if not applicable)*
3. List all sanctions issued against or imposed upon Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges where such sanctions were either imposed in the past ten (10) years or, if imposed prior to that, are still in effect. List all known material ongoing investigations regarding Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, imposed by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges:
*(Enter N/A if not applicable)*

4. Provide a summary of any bankruptcy, dissolution, merger, or acquisition of Certifying Entity in the past ten (10) years (include date, jurisdiction, and other relevant details):
*(Enter N/A if not applicable)*

5. List all wholesale or retail energy market-related operations in North America where Certifying Entity is currently participating, or, in the past five (5) years, has previously participated other than in the New England Markets (e.g., PJM - FTRs):
*(Enter N/A if not applicable)*

6. Describe if Certifying Entity or any of Certifying Entity's Principals, Personnel, or any Predecessor of the foregoing ever had its participation or membership in any independent system operator or regional transmission organization (domestic or international) terminated, its registration/membership application denied, or is subject to an existing uncured suspension from participating in the markets of any independent system operator or regional transmission organization (domestic or international), each in the past five (5) years.
*(Enter N/A if not applicable)*

**If you are currently an active participant and this is your annual submission you do not have to complete Question 7 and can skip to the signature block below. If you are in the process of applying for membership with the ISO you are required to answer the additional questions listed below.**

7. Describe how Certifying Entity plans to fund its operations, including persons or entities providing financing and such person(s)' or entity(ies)' relationship to the Certifying Entity. Include any relationships that may impact Certifying Entity's ability to (a) comply with the time frames to post

[1] Personnel means any person, current or former, responsible for decision making regarding Certifying Entity's transaction of business in the New England Markets, including, without limitation, decisions regarding risk management and trading, or any person, current or former, with access to enter transactions into ISO systems. Disclosures regarding former Personnel shall only be required for when such Personnel was employed by Certifying Entity.

[4] Predecessor shall mean any person or entity whose liabilities, including liabilities arising under the Tariff, have or may have been retained or assumed by Certifying Entity, either contractually, by operation of law or considering all relevant factors, including the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base.

financial assurance and/or pay invoices or other amounts owed to the ISO, each as required by the Tariff; or (b) provide a first priority perfected security interest in required financial assurance to the ISO:

Certifying Entity: _____

By: _____
(Signature)

Print Name: _____

Title: _____

Date: _____

** To satisfy the disclosure requirements above, a Certifying Entity may attach additional materials and may provide the ISO with filings made to the SEC or other similar regulatory agencies that include substantially similar information to that required above, provided that Certifying Entity clearly indicates where the specific information is located in those filings.

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III.13.3.1 Resources Subject to Critical Path Schedule Monitoring.

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III.13.4.2.1.2.1.3 Import Capacity Resources Backed by an External Control Area.

III.13.4.2.1.2.1.3.1 Import Capacity Resources Backed by One or More External Resources.

III.13.4.2.1.2.1.4 Demand Capacity Resources.

III.13.4.2.1.2.1.4.1 Summer ARA Qualified Capacity.

III.13.4.2.1.2.1.4.2 Winter ARA Qualified Capacity.

III.13.4.2.1.2.1.5 Distributed Energy Capacity Resources.

III.13.4.2.1.2.1.5.1 Summer ARA Qualified Capacity.

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| III.13.4.2.1.2.2.2 | Intermittent Power Resources. |
| III.13.4.2.1.2.2.2.1 | Summer ARA Qualified Capacity. |
| III.13.4.2.1.2.2.2.2 | Winter ARA Qualified Capacity. |
| III.13.4.2.1.2.2.3 | Import Capacity Resources. |
| III.13.4.2.1.2.2.3.1 | Import Capacity Resources Backed by an External Control Area. |
| III.13.4.2.1.2.2.3.2 | Import Capacity Resources Backed by One or More External Resources. |
| III.13.4.2.1.2.2.4 | Demand Capacity Resources. |
| III.13.4.2.1.2.2.4.1 | Summer ARA Qualified Capacity. |
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| III.13.4.2.1.2.2.5 | Distributed Energy Capacity Resources. |
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III.15.7.1.4 [Reserved.]

III.15.7.1.5 Demand Capacity Resources with Capacity Supply Obligations

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# 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, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation 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 Supplied 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, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation 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) The following 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) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.

(iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR 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 steam 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) An Establish Claimed Capability Audit may be performed only by a Generator Asset.

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

(c) For a newly commercial Generator Asset:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within five 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.

(d) 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 five 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.

(e) 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.

(f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.

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

(i) Initiate an Establish 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.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(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.

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

| **Duration Required for an Establish Claimed Capability Audit** | |
|---|---|
| **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 (Electric Storage)<br>Hydraulic Turbine – Other | 2 |
| Hydro-Conventional Daily Pondage<br>Hydro-Conventional Run of River<br>Hydro-Conventional Weekly | 2 |
| Wind<br>Photovoltaic<br>Fuel Cell | 2 |
| Other Electric Storage (Excludes Hydraulic Turbine - Reversible) | 2 |

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

**III.1.5.1.3. Seasonal Claimed Capability Audits.**

(a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.

(b) 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).

(c) 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.

(d) Except as provided in Section III.1.5.1.3(n) 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.

(e) 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.

(f) 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 fifth 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.

(g) 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.

(h) 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(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(i) 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.

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

| **Duration Required for a Seasonal Claimed Capability Audit** | |
|---|---|
| **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 (Electric Storage)<br>Hydraulic Turbine-Other | 2 |
| Hydro-Conventional Weekly | 2 |
| Fuel Cell | 1 |
| Other Electric Storage (Excludes Hydraulic Turbine - Reversible) | 2 |

(k) 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.

(l) 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.

(m) 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.

(n) 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(f).

(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(d)(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(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

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

**III.1.5.1.3.1 Seasonal DR Audits.**

(a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

(b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.

(c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of April through November;

(d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of December through March.

(e) A Seasonal DR Audit may be performed either:

(i) At the request of a Market Participant as described in subsection (f) below; or

(ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.

(f) If a Market Participant requests a Seasonal DR Audit:

(i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.

(ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.

(iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

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

(g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth 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 DR Audit.

(iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.

(iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

(h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.

(i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.

(j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

(k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.

(l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.

(m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

(n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.

(o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

**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 either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both 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 for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset 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 for a Generator Asset 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) The 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) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) For Generator Assets, 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.

(iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

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

| **Duration Required for an ISO-Initiated Claimed Capability Audit** | |
|---|---|
| **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 (Electric Storage)<br>Hydraulic Turbine – Other | 2 |
| Hydro-Conventional Daily Pondage<br>Hydro-Conventional Run of River<br>Hydro-Conventional Weekly | 2 |
| Wind<br>Photovoltaic<br>Fuel Cell | 2 |
| Other Electric Storage (Excludes Hydraulic Turbine – Reversible) | 2 |
| Demand Response Resource | 1 |

(g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource 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 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 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 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(f).

(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 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 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.

**III.1.5.3 Reactive Capability Audits.**

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

(i) A lagging Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to provide reactive power to the transmission system at a specified real power output or consumption.

(ii) A leading Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to absorb reactive power from the transmission system at a specified real power output or consumption.

(b) The ISO shall develop a list of Reactive Resources that must conduct Reactive Capability Audits. The list shall include Reactive Resources that: (i) have a gross individual nameplate rating greater than 20 MVA; (ii) are directly connected, or are connected through equipment designed primarily for delivering real or reactive power to an interconnection point, to the transmission system at a voltage of 100 kV or above; and (iii) are not exempted from providing voltage control by the ISO. Additional criteria to be used in adding a Reactive Resource to the list includes, but is not limited to, the effect of the Reactive Resource on System Operating Limits, Interconnection Reliability Operating Limits, and local area voltage limits during the following operating states: normal, emergency, and system restoration.

(c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall perform both a lagging Reactive Capability Audit and a leading Reactive Capability Audit.

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

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

(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.

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

(i) there is a change in the Reactive Resource that may affect the reactive power capability of the Reactive Resource;

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

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

(h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may 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 Transmission Constraint Penalty Factors.**

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is $10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is $30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any transmission constraint is $30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

**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. The ISO shall use a joint optimization process to serve Day-Ahead Market energy requirements and Day-Ahead Ancillary Services requirements, as described in Section III.1.10.8(a).

(b) [Reserved].

(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 LMP-Based Energy Pricing**.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the 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 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 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 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.1.7.9A Day-Ahead Ancillary Services Prices.**

The prices paid by the ISO for the provision of Day-Ahead Ancillary Services in the New England Markets will reflect Day-Ahead Ancillary Services clearing prices determined by the ISO in accordance with the ISO New England Filed Documents.

**III.1.7.10 Other Transactions.**

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.

**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 Seasonal DR Audit Value of an Active Demand Capacity Resource.**

(a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through

November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.

(b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

**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 endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. 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 Ramping.**

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to potential referral under Section III.A.19.

**III.1.7.19 Real-Time Reserve Designation**.

The ISO shall determine the Real-Time Reserve Designation for each eligible Resource in accordance with this Section III.1.7.19. The Real-Time Reserve Designation shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve.

**III.1.7.19.1 Eligibility.**

To be eligible to receive a Real-Time Reserve Designation, a Resource must meet all of the criteria enumerated in this Section III.1.7.19.1. A Resource that does not meet all of these criteria is not eligible to provide Operating Reserve and will not receive a Real-Time Reserve Designation.

(1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.

(2) The Resource must not be part of the first contingency supply loss.

(3) The Resource must not be designated as constrained by transmission limitations.

(4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)

(5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

**III.1.7.19.2 Calculation of Real-Time Reserve Designation.**

**III.1.7.19.2.1 Generator Assets.**

**III.1.7.19.2.1.1 On-line Generator Assets.**

The Manual Response Rate used in calculations in this section shall be the lesser of the Generator Asset's offered Manual Response Rate and its audited Manual Response Rate as described in Section III.1.5.2.

(a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Non-Spinning Reserve shall be zero. For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit).

(c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

**III.1.7.19.2.1.2 Off-line Generator Assets.**

For an off-line Generator Asset that is not a Fast Start Generator, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).

(c) **Thirty-Minute Operating Reserve.** For an off-line Fast Start Generator, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Fast Start Generator's Offered CLAIM30, its CLAIM30, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Thirty-Minute Operating Reserve shall be zero, except during the last thirty minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Thirty-Minute Operating Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires), minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Fast Start Generator pursuant to subsection (b) above.

**III.1.7.19.2.2 Dispatchable Asset Related Demand.**

**III.1.7.19.2.2.1 Storage DARDs.**

(a) **Ten-Minute Spinning Reserve.** For a Storage DARD, Ten-Minute Spinning Reserve shall be calculated as the absolute value of the amount of current telemetered consumption.

(b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.

(c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

**III.1.7.19.2.2.2 Dispatchable Asset Related Demand Other Than Storage DARDs.**

(a) **Ten-Minute Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit). For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit).

(c) **Thirty-Minute Operating Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (a) above. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Non-Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (b) above.

**III.1.7.19.2.3 Demand Response Resources.**

For a Demand Response Resource that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2.

**III.1.7.19.2.3.1 Dispatched.**

(a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be

calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction). For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction).

(c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within thirty minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction) minus the Ten-Minute Spinning Reserve quantity calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

**III.1.7.19.2.3.2 Non-Dispatched.**

For a Demand Response Resource that is not being dispatched that is not a Fast Start Demand Response Resource, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Demand Response Resource's Offered CLAIM10, its CLAIM10, and its Maximum Reduction.

(c) **Thirty-Minute Operating Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Demand Response Resource's Offered CLAIM30, its CLAIM30, and its Maximum Reduction, minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Demand Response Resource pursuant to subsection (b) above.

**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 Resources 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, consumption, or demand reduction levels of Generator Assets, DARDs, 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, 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.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands 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.1.7.21 SATOA Participation in Markets:** A Node will be established for each SATOA. A Market Participant's market activity, transactions, and actions taken at a SATOA's Node and a SATOA's participation in the New England Markets shall be limited to those necessary to consume or inject energy from or to PTF for any period, magnitude, and duration identified as necessary to: (1) address the applicable system needs or provide the transmission function for which the SATOA was selected as the preferred solution; or (2) as specified in the ISO New England Operating Documents, avoid or mitigate Load Shedding after all available Dispatchable Resources that can effectively provide relief to avoid or mitigate the Load Shedding have been dispatched.

**III.1.8 Day-Ahead Ancillary Services and Forecast Energy Requirement.**

**III.1.8.1 Day-Ahead Ancillary Services Offers.**

Market Participants may submit Day-Ahead Ancillary Services Offers for the Operating Day in the Day-Ahead Ancillary Services Market as specified in this Section III.1.8.1.

(a) Each Day-Ahead Ancillary Services Offer shall be associated with a specific Generator Asset, Demand Response Resource, or DARD for which the Market Participant has submitted a corresponding Supply Offer, Demand Reduction Offer, or Demand Bid in the Day-Ahead Energy Market for the same hour of the Operating Day.

(b) Each Day-Ahead Ancillary Services Offer shall specify: (i) the hour of the Operating Day for which the Day-Ahead Ancillary Services Offer applies; (ii) product-specific offer prices, in $/MWh, that are greater than or equal to zero for the Day-Ahead Ancillary Services; and (iii) a single offer quantity, in MWh, that is greater than or equal to zero. The offer prices for the Day-Ahead Ancillary Services shall not exceed the Forecast Energy Requirement Penalty Factor as specified in Section III.2.6.2(d) of this Market Rule 1. The offer quantity shall not exceed the Economic Maximum Limit specified in the associated Supply Offer, the Maximum Reduction specified in the associated Demand Reduction Offer, or the Maximum Consumption Limit specified in the associated Demand Bid.

(c) As part of its Day-Ahead Ancillary Services Offer, a Market Participant is permitted to specify a Maximum Daily Award Limit quantity, in MWh, that is greater than or equal to zero.

(d) For each hour of the Operating Day, a Market Participant may submit only one Day-Ahead Ancillary Services Offer associated with a specific Generator Asset, Demand Response Resource, or DARD.

(e) Day-Ahead Ancillary Services Offers shall be submitted by the offer submission deadline for the Day-Ahead Market specified in Section III.1.10.1A of this Market Rule 1. A Day-Ahead Ancillary Services Offer shall not remain in effect for subsequent Operating Days.

**III.1.8.2 Day-Ahead Ancillary Services Strike Price.**

(a) For each hour of the Operating Day, the ISO shall specify the Day-Ahead Ancillary Services Strike Price in $/MWh. The value of the Day-Ahead Ancillary Services Strike Price represents an amount that is the greater of (i) $10/MWh greater than a forecast of the expected hourly Real-Time Hub Price for such hour of the Operating Day and (ii) zero.

(b) The forecast used to determine the Day-Ahead Ancillary Services Strike Price shall be based on a publicly-available forecasting algorithm developed by the ISO. The ISO shall describe the publicly-available forecasting algorithm to Market Participants and shall periodically review and assess the efficacy of the forecasting algorithm. The ISO shall notify stakeholders of any potential revisions to the ISO's forecasting algorithm prior to implementing such revisions.

(c) In the event that the ISO is not able to utilize the ISO-developed forecasting algorithm described in subsection (b) above due to hardware, software, or telecommunications problems, human error, or exigent circumstances not contemplated by this market rule, the ISO shall determine the Day-Ahead Ancillary Services Strike Price using the best forecast available and shall disclose the use of such substitute forecast to Market Participants as soon as practicable.

**III.1.8.3 Day-Ahead Flexible Response Services Demand Quantities.**

The Day-Ahead Ancillary Services Market shall endeavor to procure the Day-Ahead Flexible Response Services Demand Quantities specified in this Section III.1.8.3.

(a) For each hour of the Operating Day, the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the Ten-Minute Spinning Reserve Requirement projected Day-Ahead.

(b) For each hour of the Operating Day, the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the Ten-Minute Reserve Requirement projected Day-Ahead.

(c) For each hour of the Operating Day, the Day-Ahead Minimum Total Reserve Demand Quantity shall be equal to the Minimum Total Reserve Requirement projected Day-Ahead.

(d) For each hour of the Operating Day, the Day-Ahead Total Reserve Demand Quantity shall be equal to the Total Reserve Requirement projected Day-Ahead.

**III.1.8.4 Forecast Energy Requirement Demand Quantity.**

For each hour of the Operating Day, the Forecast Energy Requirement Demand Quantity shall be equal to the ISO forecast for the total load in the New England Control Area produced pursuant to Section III.1.10.1A(h) of this Market Rule 1.

**III.1.9 Pre-scheduling.**

**III.1.9.1 Offer and Bid Caps and Cost Verification for Offers and Bids.**

**III.1.9.1.1 Cost Verification of Resource Offers.**

The incremental energy values of Supply Offers and Demand Response Resources above $1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or $1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than $1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be

performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to $1,000/MWh, then the adjusted offer for the Resource is set at $1,000/MWh;

(ii) If the Reference Level value is greater than $1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

**III.1.9.1.2 Offer and Bid Caps.**

(a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at $2,000/MWh.

(b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.

(c) Supply Offers and Demand Reduction Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

(d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.

(e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

**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 Generator Asset 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 the Day-Ahead Market and a Real-Time Energy Market.

(b) The Day-Ahead Market shall enable Market Participants to purchase and sell energy and sell ancillary services 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 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 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 Generator Assets or Demand Response 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 or Demand Reduction Offers.

**III.1.10.1A Energy and Day-Ahead Ancillary Services Market Scheduling**.
Market Participants may submit offers and bids in the Day-Ahead Market until 10:30 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) **Locational Demand Bids –** 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 applicable Day-Ahead Price, (ii) hourly schedules for Resources 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 Demand Bid Cap and Virtual Cap.

(b) **External Transactions –** All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets 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. 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) In the Day-Ahead Energy Market, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) In the Day-Ahead Energy Market, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction 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.

(c) **Generator Asset Supply Offers –** Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

(i) Shall specify the Resource and 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 prices and quantities in a Block may each vary on an hourly basis;

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

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type 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 Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including 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 an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and

(vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.

**(d) DARD Demand Bids –** Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including 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;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

(iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers –** Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.

(f) **Demand Reduction Threshold Price –** The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

(a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.

(c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

(d) A historic threshold price $P_{th}$ shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th}X - \frac{FPI_c}{FPI_h}$$

where $FPI_h$ is the historic fuel price index for the same month of the previous year, and $FPI_c$ is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction 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 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, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) **Load Estimate** – 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) **Prorated Supply** – 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) **Prorated Demand** – 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) **Virtuals** – 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.

(l) **Day-Ahead Ancillary Services Offers** – Market Participants selling into the New England Markets from Generator Assets or Demand Response Resources or participating in the New England Markets with DARDs, and that have submitted Supply Offers, Demand Reduction Offers, or Demand Bids for the following Operating Day, as described in subsections (c), (d), and (e) of this Section III.1.10.1A, may submit Day-Ahead Ancillary Services Offers for the following Operating Day. Day-Ahead Ancillary Services Offers shall be submitted to the ISO in accordance with Section III.1.8.1 of this Market Rule 1.

**III.1.10.2 Pool-Scheduled Resources.**

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs or Demand Response

Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume 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 supply or consumption, ancillary services, 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 and ancillary services 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 Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids, ancillary services offers and requirements, and the Forecast Energy Requirement Demand Quantity.

(c) Market Participants offering energy from 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) 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. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD 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. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource shall not be Self-Scheduled.

**III.1.10.4 External Resources**.

Market Participants with External Resources may submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

**III.1.10.5 Dispatchable Asset Related Demand.**

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

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

(ii) 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;

(iii) abide by the ISO maintenance coordination procedures; and

(iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

**III.1.10.6 Electric Storage**

A storage facility is a facility that is capable of receiving electricity and storing the energy for later injection of electricity into the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

(i) comprise one or more storage facilities at the same point of interconnection;

(ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;

(iii) be directly metered;

(iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;

(v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;

(vi) settle its injection of electricity to the grid as a Generator Asset and any receipt of electricity from the grid as a DARD;

(vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and

(viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility; and

(ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and

(iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.

(c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility;

(ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;

(iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;

(iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;

(v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;

(vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;

(vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and

(viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).

(d) In clearing the Day-Ahead Energy Market, the ISO will respect Electric Storage Facility Initial State of Charge, Round Trip Efficiency, Maximum State of Charge, and Minimum State of Charge.

(e) A storage facility incapable of receiving and storing electricity from the grid may participate in the New England Markets as a Continuous Storage Facility, so long as that facility satisfies all Continuous Storage Facility registration and participation requirements that are not solely related to consumption capability. Notwithstanding Section III.1.10.6(a), Section III.1.10.6(c), and any other related provisions, such non-consuming storage facilities shall not be required to:

(i) be capable of consuming at least 0.1 MW from the grid; or

(ii) be capable of modifying consumption responsive to Dispatch Instructions.

(f) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:

a. A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.

b. A storage facility's charging energy shall not qualify as, or be billed to, a Storage DARD if that facility's charging energy is included in another Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging energy.

c. The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.

d. Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.

(v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.

(g) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.

(h) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.

(i) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered

and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

(j) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.

(k) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

**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 procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.

(d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID 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, as determined in accordance with Section III.12.4, that experienced price separation in the Annual Capacity Auction as determined in accordance with Section III.15.4.2.2(j) of Market Rule 1;

(2) The External Transaction is directly associated with an Export Offer Segment that did not receive a Capacity Supply Obligation in the Annual Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the unobligated Export Offer Segment;

(3) The External Node associated with the unobligated Export Offer Segment 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) Annual Capacity Auction 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 Offer Segment that did not receive a Capacity Supply Obligation in the Annual Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the unobligated Export Offer Segment;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Offer Segment 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 or Annual 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 Annual Capacity Auction 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 Annual Capacity Auction Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and Annual Capacity Auction 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 Transaction Scheduling**.

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 15-minute 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 e-Tag ID 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 the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, permit the transaction to be scheduled.

**III.1.10.8 Scheduling Considerations.**

(a) In scheduling the Day-Ahead Market, the ISO shall use its best efforts to determine the security-constrained economic commitment and dispatch that jointly optimizes: (i) Demand Bids, Decrement Bids, Demand Reduction Offers, Supply Offers, Increment Offers, and External Transactions, for energy; (ii) Day-Ahead Ancillary Services Offers to satisfy the Day-Ahead Flexible Response Services Demand Quantities; and (iii) Supply Offers, Demand Reduction Offers, External Transactions, and Day-Ahead Ancillary Services Offers to satisfy the Forecast Energy Requirement Demand Quantity.

In making the determination specified in this subsection (a), the ISO shall take into account, as applicable: (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 ancillary services; (vi) the operational capabilities of any Resource to adjust the output, consumption, or demand reduction within the operating characteristics and parameters specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, or Demand Bid and any audited values of such operating characteristics and parameters; (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.

In scheduling the Day-Ahead Market, the following limitations shall apply:

(i) For purposes of satisfying the Day-Ahead Flexible Response Services Demand Quantities specified in Sections III.1.8.3(a) through (d), the ISO shall not take into account a Day-Ahead Ancillary Services Offer unless the Generator Asset, Demand Response Resource, or DARD associated with the Day-Ahead Ancillary Services Offer meets the eligibility requirements enumerated in Section III.1.7.19.1.

(ii) For purposes of satisfying the Forecast Energy Requirement Demand Quantity specified in Section III.1.8.4, the ISO shall not take into account a Day-Ahead Ancillary Services Offer unless the offer is associated with a Generator Asset or Demand Response Resource that meets the following conditions:

(1) The Generator Asset or Demand Response Resource is, for the applicable hour, either scheduled for energy in the Day-Ahead Energy Market or is a Fast Start Generator or Fast Start Demand Response Resource.

(2) The Generator Asset or Demand Response Resource is not designated as constrained by transmission limitations, as described in Section III.1.7.19.1(3).

(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 and ancillary services 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 Market cannot 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. The ISO shall use its best efforts to determine the least-cost means to satisfy any remaining reliability requirements of the New England Control Area for the Operating Day.

(d) Market Participants shall pay and be paid for the quantities of energy and ancillary services scheduled in the Day-Ahead Market based upon applicable 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 Resources and to direct that schedules be changed to address an actual or potential 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 Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. 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) During the Re-Offer Period, Market Participants may submit revisions to the price of 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 request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. 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(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) 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 Generator Assets), and the quantity and price pairs of its Blocks may be modified.

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

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

(e) 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. A Market Participant may not request to Self-Schedule a Demand Response Resource. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

(f) 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(c), 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 at a specified value. 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 at or above the requested amount for the hour in question.

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

(i) 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 or Consumption and Demand Reduction.**

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource 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, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) 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; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) 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 Dispatchable Resources.**

With the exception of Settlement Only Resources, Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, and nuclear-powered Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

(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 Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable 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 for a Dispatchable Resource 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 Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind, solar, and hydro Intermittent Power Resources that are not Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

(i) A Market Participant may elect, but is not required, to have a wind, solar, or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.

(ii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.

(f) The ISO may request that dual-fuel Generator Assets 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-fuel Generator Assets 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-fuel Generator Assets 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 Dispatchability Requirements for Intermittent Power Resources.**

(a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.

(b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redeclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

(c) Wind and solar Generator Assets that are not Settlement Only Resources shall electronically transmit meteorological and forced outage data, as specified below, to the ISO, over a secure network, using the protocol specified in the ISO Operating Documents, for the development and deployment of wind and solar power production forecasts.

Wind Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

(i) at least once every 30 seconds: wind speed, and wind direction;

(ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, and standard deviation of ambient air relative humidity;

(iii) at least once every 5 minutes: Real-Time High Operating Limit, Wind High Limit, wind turbine counts; and

(iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Wind Plant Future Availability.

Solar Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

(i) at least once every 30 seconds: irradiance;

(ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, standard deviation of ambient air relative humidity, wind speed, and wind direction;

(iii) at least once every 5 minutes: Real-Time High Operating Limit, and Solar High Limit; and

(iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Solar Plant Future Availability.

**III.1.11.6 Non-Dispatchable Resources.**

Non-Dispatchable Resources are subject to the following requirements:

(a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource 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.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

**III.13.5. Bilateral Contracts in the Forward Capacity Market.**

Market Participants shall be permitted to enter into Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, and Capacity Load Obligation Bilaterals in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

**III.13.5.1. Capacity Supply Obligation Bilaterals.**

Capacity Supply Obligation Bilaterals are available for monthly periods. The qualification of resources subject to a Capacity Supply Obligation Bilateral is determined in the same manner as the qualification of resources is determined for reconfiguration auctions as specified in Section III.13.4.2.

A resource having a Capacity Supply Obligation seeking to shed that obligation (Capacity Transferring Resource) may enter into a bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part (Capacity Supply Obligation Bilateral), to a resource, or portion thereof, having Qualified Capacity for that Capacity Commitment Period that is not already obligated (Capacity Acquiring Resource), subject to the following limitations.

(a) A Capacity Supply Obligation Bilateral must be coterminous with a calendar month.

(b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the monthly Capacity Supply Obligation of the Capacity Transferring Resource. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the amount of unobligated Qualified Capacity (that is, Qualified Capacity as determined in the most recent Forward Capacity Auction or reconfiguration auction qualification process that is not subject to a Capacity Supply Obligation) of the Capacity Acquiring Resource during the month covered by the Capacity Supply Obligation Bilateral, as determined in the qualification process for the most recent Forward Capacity Auction or annual reconfiguration auction prior to the submission of the Capacity Supply Obligation Bilateral to the ISO.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource's unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.

(d) [Reserved.]

(e) [Reserved.]

(f) [Reserved.]

(g) [Reserved.]

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant Obligation Month.

(j) A resource that is not expected to achieve FCM Commercial Operation prior to the end of a given Obligation Month in accordance with posted schedules may not submit a transaction as a Capacity Acquiring Resource for that month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a Capacity Supply Obligation Bilateral in an amount up to the absolute value of its Capacity Supply Obligation.

**III.13.5.1.1. Process for Approval of Capacity Supply Obligation Bilaterals.**

**III.13.5.1.1.1. Timing of Submission and Prior Notification to the ISO.**
The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

**III.13.5.1.1.2. Application.**

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, in $/kW-month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

**III.13.5.1.1.3. ISO Review.**

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral, and shall reject the Capacity Supply Obligation Bilateral if any of the provisions of this Section III.13.5.1 are not met. For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.

(b) After the close of the relevant submittal window, each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards will remain satisfied if the capacity associated with the Capacity Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO's reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation outage information, and will include transmission security studies. The ISO will review all confirmed Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. The ISO shall obtain and consider information from the Local Control Center regarding whether the Capacity Supply Obligation of the Capacity Transferring Resource is needed for local system conditions and whether it is adequately replaced by the Acquiring Resource.

The ISO will approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. If multiple Capacity Supply Obligation Bilaterals are submitted between the same resources, they may be reviewed together as one transaction and the most recent confirmation time among the related transactions will be used to determine the review order of the grouped transaction. Transactions that cannot meet the applicable reliability needs will only be accepted or rejected in their entirety and the resources will not be accepted or rejected in part for purposes of that transaction. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected for reliability reasons the Lead Market Participant or Project Sponsor, as appropriate, for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the reliability need prompting such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

**III.13.5.1.1.4. Approval.**

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply Obligation of the Capacity Acquiring Resource shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

**III.13.5.2. Capacity Load Obligations Bilaterals.**

A Market Participant having a Capacity Load Obligation seeking to shed that obligation ("Capacity Load Obligation Transferring Participant") may enter into a bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone ("Capacity Load Obligation Bilateral") to any Market Participant seeking to acquire a Capacity Load Obligation ("Capacity Load Obligation Acquiring Participant"). A Capacity Load Obligation Bilateral must be in whole calendar month increments, may not exceed one year in duration, and must begin and end within the same Capacity Commitment Period. A Capacity Load Obligation Transferring Participant will be permitted to transfer, and a Capacity Load Obligation Acquiring Participant will be permitted to acquire, a Capacity Load Obligation if after entering into a Capacity Load Obligation Bilateral and submitting related information to the ISO within the specified submittal time period, the ISO approves such Capacity Load Obligation Bilateral.

**III.13.5.2.1. Process for Approval of Capacity Load Obligation Bilaterals.**

**III.13.5.2.1.1. Timing.**

Either the Capacity Load Obligation Transferring Participant or the Capacity Load Obligation Acquiring Participant may submit a Capacity Load Obligation Bilateral to the ISO. All Capacity Load Obligation Bilaterals must be submitted to the ISO in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial daily settlements of payments and charges associated with the Forward Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 pm on the first Business Day of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

**III.13.5.2.1.2. Application.**

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following : (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

**III.13.5.2.1.3. ISO Review.**

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section II.13.5.2 are not met.

**III.13.5.2.1.4. Approval.**

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral.

**III.13.5.3. [Reserved.]**

**III.13.5.4 Annual Reconfiguration Transactions.**

Annual Reconfiguration Transactions are available for annual reconfiguration auctions for Capacity Commitment Periods beginning on or after June 1, 2020, except that Annual Reconfiguration Transactions are not available for the first annual reconfiguration auction for the Capacity Commitment Period beginning on June 1, 2020.

**III.13.5.4.1 Timing of Submission.**

The Lead Market Participant or Project Sponsor for either a Capacity Transferring Resource or a Capacity Acquiring Resource may submit an Annual Reconfiguration Transaction to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Annual Reconfiguration Transactions as soon as practicable after the issuance of Forward Capacity Auction results. An Annual Reconfiguration Transaction must be confirmed by the party other than the party submitting the Annual Reconfiguration Transaction to the ISO no later than the end of the relevant submittal window.

**III.13.5.4.2 Components of an Annual Reconfiguration Transaction.**

The submission of an Annual Reconfiguration Transaction must include the following:

1. the resource identification number of the Capacity Transferring Resource;
2. the applicable Capacity Commitment Period;
(3) the resource identification number of the Capacity Acquiring Resource, and;
3. a price ($/kW-month), quantity (MW) and Capacity Zone, to be used in settling the Annual Reconfiguration Transaction.

The maximum quantity of an Annual Reconfiguration Transaction is the higher of:

(1) the Capacity Transferring Resource's maximum demand bid quantity determined pursuant to Section III.13.4.2.2(b), less the quantity of any previously confirmed Annual Reconfiguration Transactions, and;

(2) the Capacity Acquiring Resource's maximum supply offer quantity determined pursuant to Section III.13.4.2.1.1, less the quantity of any previously confirmed Annual Reconfiguration Transactions.

An Annual Reconfiguration Transaction may not be submitted unless the maximum demand bid quantity and maximum supply offer quantity are each greater than zero.

Each Annual Reconfiguration Transaction is limited to a single Capacity Acquiring Resource and a single Capacity Transferring Resource.

If any demand bid of a Capacity Transferring Resource or supply offer of a Capacity Acquiring Resource that is associated with an Annual Reconfiguration Transaction is rejected for reliability reasons pursuant to Section III.13.2.2(c) or Section III.13.4.2.1.5, respectively, the Annual Reconfiguration Transaction is cancelled.

**III.13.5.4.3 Settlement of Annual Reconfiguration Transactions.**

Annual Reconfiguration Transactions are settled on a daily basis during the applicable Capacity Commitment Period. The total of the daily payment amounts for the month is equal to the transaction quantity multiplied by the difference between the annual reconfiguration auction clearing price and the transaction price. If the payment amount is positive, payment is made to the Lead Market Participant with the Capacity Transferring Resource and charged to the Lead Market Participant with the Capacity Acquiring Resource. If the payment amount is negative, payment is made to the Lead Market Participant with the Capacity Acquiring Resource and charged to the Lead Market Participant with the Capacity Transferring Resource.

**III.13.7. Performance, Payments and Charges in the FCM.**

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

**III.13.7.1. Capacity Base Payments**.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1.

**III.13.7.1.1. Payments and Charges Reflecting Capacity Supply Obligations.**

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.13.7.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Forward Capacity Auction**. For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated

with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

(d) **Substitution Auctions.** For a resource whose offer or bid has cleared in a substitution auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the substitution auction clearing price. Notwithstanding the foregoing, the monthly capacity charge for a demand bid cleared at a substitution auction clearing price above its bid price shall be calculated using its bid price.

**III.13.7.1.3. Export Capacity.**

If there are any Export Bids or Administrative Export De-List Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows.

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$ ] x Cleared MWs of Export Bid or Administrative Export De-List Bid]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$ ] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.5.2.

**III.13.7.1.4. [Reserved.]**

**III.13.7.2 Capacity Performance Payments.**

**III.13.7.2.1 Definition of Capacity Scarcity Condition.**

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

**III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.**

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.13.7.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition

shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource or Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.13.7.2.2(c), for any On-Peak Demand Resource or Seasonal Peak Demand Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.13.7.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(i) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource

was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(ii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

(e) A Distributed Energy Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Metered Quantity for Settlement and Reserve Quantity for Settlement of all the components of its constituent Distributed Energy Resource Aggregations; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Based on the Real-Time operational coordination, the resource must follow any distribution system limitation and update its physical parameters accordingly. The Actual Capacity Provided cannot be less than zero.

(i) The Real-Time demand reduction of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled

curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

**III.13.7.2.3 Capacity Balancing Ratio.**

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

provided, however, that the Capacity Balancing Ratio shall not exceed a value of 1.0.

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

**III.13.7.2.4 Capacity Performance Score.**

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

**III.13.7.2.5 Capacity Performance Payment Rate.**

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025, the Capacity Performance Payment Rate shall be $5455/MWh. For the period beginning on June 1, 2025 and ending on August 31, 2026, the Capacity Performance Payment Rate shall be $9337/MWh. Thereafter, the Capacity Performance Payment Rate shall be $3500/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

**III.13.7.2.6 Calculation of Capacity Performance Payments.**

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

**III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.**

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

**III.13.7.3.1 Monthly Stop-Loss.**

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the

product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month).

**III.13.7.3.2 Annual Stop-Loss.**

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (FCAcp – FCAsp) – (12 months x FCAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

**III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments.**

For Capacity Scarcity Conditions, as described in Section III.13.7.2.1, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a), (b), and (c) below.

(a) If the sum of all Capacity Performance Payments to all resources subject to a Capacity Scarcity Condition in an Obligation Month is positive, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the deficiency shall be charged to resources in proportion to the sum of each such resource's positive Capacity Performance Score for the Obligation Month.

(b) If the sum of all Capacity Performance Payments to all resources subject to a Capacity Scarcity Condition in an Obligation Month is negative, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the excess shall be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess shall be further allocated to other resources in the same manner as described in this Section III.13.7.4(b).

(c) If a deficiency of Capacity Performance Payments exists due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the deficiency shall be charged to all resources subject to a Capacity Scarcity Condition in an Obligation Month that have not reached their stop-loss limit (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. If the charge described in Section III.13.7.4(a) or the charge described in this Section III.13.7.4(c) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss limit described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(c).

**III.13.7.5. Charges to Market Participants with Capacity Load Obligations.**

**III.13.7.5.1. Calculation of Capacity Charges Prior to June 1, 2022.**

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning prior to June 1, 2022. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing

Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month may also receive a failure to cover credit equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone, and; (b) the sum of all failure to cover charges in the Capacity Zone calculated pursuant to Section III.13.3.4(b), divided by total Capacity Load Obligation in the Capacity Zone.

**III.13.7.5.1.1. Calculation of Capacity Charges On and After June 1, 2022.**

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning on or after June 1, 2022. For purposes of this Section III.13.7.5.1.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in subsection (b) of Sections III.13.7.5.1.1.1 through III.13.7.5.1.1.9 will be divided by the number of days in the month to derive a daily settlement value.

**III.13.7.5.1.1.1 Forward Capacity Auction Charge.**

The FCA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone FCA Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone FCA Costs, for each Capacity Zone, are the Total FCA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total FCA Costs are the sum of, for all Capacity Zones, (i) Capacity Supply Obligations in each zone (the total obligation awarded to or shed by resources in the Forward Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.13.7.5.1.1.6 and excluding any obligations procured in the Forward

Capacity Auction that are terminated pursuant to Section III.13.3.4A) multiplied by the applicable clearing price from the auction in which the obligation was awarded to (or shed by) the resource, and (ii) the difference between the bid price and the substitution auction clearing price that was not included in the capacity charge pursuant to the second sentence of Section III.13.7.1.1(d). Capacity Supply Obligations awarded to Proxy De-List Bids in the primary auction, or shed by demand bids entered into the substitution auction on behalf of a Proxy De-List Bid, are excluded from Total FCA Costs.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

**III.13.7.5.1.1.2 Annual Reconfiguration Auction Charge.**

The total annual reconfiguration auction charge, for each Capacity Zone and each associated annual reconfiguration auction, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone Annual Reconfiguration Auction Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone Annual Reconfiguration Auction Costs, for each Capacity Zone, are the Total Annual Reconfiguration Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total Annual Reconfiguration Auction Costs are the sum, for all Capacity Zones and each associated annual reconfiguration auction, of the product of the Capacity Supply Obligations acquired through the annual reconfiguration auction in each zone (adjusted for any obligations procured in the annual reconfiguration auction that are subsequently terminated pursuant to Section III.13.3.4A) and the zonal annual reconfiguration auction clearing price, minus the sum, for all Capacity Zones, of the product of the amount of any Capacity Supply Obligation shed through the annual reconfiguration auction in each zone and the applicable annual reconfiguration auction clearing price.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

**III.13.7.5.1.1.3. Monthly Reconfiguration Auction Charge.**

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price, minus the sum of, for all Capacity Zones, any Capacity Supply Obligations shed through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

**III.13.7.5.1.1.4. HQICC Capacity Charge.**

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

**III.13.7.5.1.1.5. Self-Supply Adjustment.**

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied FCA Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

**III.13.7.5.1.1.6. Intermittent Power Resource Capacity Adjustment.**

The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where

Intermittent Power Resource Seasonal Variance is the difference between the FCA payments for Intermittent Power Resource in the Obligation Month and the base FCA payments for Intermittent Power Resources.

FCA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to or shed by Intermittent Power Resources in the Forward Capacity Auction process for the Obligation Month pursuant to Section III.13.2.7.6 or Section III.13.2.8.1.1 (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base FCA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the FCA Qualified Capacity procured from or shed by Intermittent Power Resources in the Forward Capacity Auction process (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Zonal Capacity Obligation in all Capacity Zones.

**III.13.7.5.1.1.7. Multi-Year Rate Election Adjustment.**

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

**III.13.7.5.1.1.8 CTR Transmission Upgrade Charge.**

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.13.7.5.4.4 (f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

**III.13.7.5.1.1.9 CTR Pool-Planned Unit Charge.**

The CTR Pool-Planned Unit charge is: (a) the total Capacity Load Obligation in all Capacity Zones less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5.

Where

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.13.7.5.4.5 (b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

**III.13.7.5.1.1.10. Failure to Cover Charge Adjustment.**

The failure to cover charge adjustment, for each Capacity Zone, is (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Failure to Cover Charges divided by Total Capacity Load Obligation.

Where:

Zonal Failure to Cover Charges are the product of: (1) the sum, for all Capacity Zones, of the failure to cover charges calculated pursuant to Section III.13.3.4(b), and; (2) the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price as determined pursuant to Section III.13.3.4.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

**III.13.7.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.**

The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals for Capacity Commitment Periods beginning prior to June 1, 2022 and excluding any additional obligations awarded to Intermittent Power Resources pursuant to Section III.13.2.7.6 that exceed the FCA Qualified Capacity procured in the Forward Capacity Auction for

Capacity Commitment Periods beginning on or after June 1, 2022) plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022) to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022).

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; when all load of a Distributed Energy Resource Aggregation participating as a Storage DARD is load associated with the receipt of electricity from the grid for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each day of the month and each Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above and (ii) the ratio of the sum of the load serving entity's daily Coincident Peak Contributions, to the sum of all load serving entities' daily Coincident Peak Contributions in that Capacity Zone.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each day of the month and each Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource, Demand Response Resource, or a Demand Response Distributed Energy Resource Aggregation.

**III.13.7.5.2.1. Charges Associated with Dispatchable Asset Related Demands.**

Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

**III.13.7.5.3. Excess Revenues**.

(a) For Capacity Commitment Periods beginning prior to June 1, 2022, revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.5.3.

(b) Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section III.13.3.4A shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

**III.13.7.5.4. Capacity Transfer Rights.**

**III.13.7.5.4.1. Definition and Payments to Holders of Capacity Transfer Rights.**

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

Capacity Transfer Rights are calculated for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone's Net Regional Clearing Price and absolute value of each Capacity Zone's Capacity Load

Obligations, as calculated in Section III.13.7.5.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources.

**III.13.7.5.4.2. Allocation of Capacity Transfer Rights.**

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.5.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface**. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface**. Except as provided in Section III.13.7.5.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

**III.13.7.5.4.3. Allocations of CTRs Resulting From Revised Capacity Zones.**
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.5.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

**III.13.7.5.4.4. Specifically Allocated CTRs Associated with Transmission Upgrades.**
(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(e) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine export interface for as long as Casco Bay continues to pay to support the transmission upgrades.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. This value will be divided by the number of days in the month to derive a daily settlement value.

**III.13.7.5.4.5. Specifically Allocated CTRs for Pool-Planned Units.**

(a) In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive for each Capacity Commitment Period an allocation of CTRs for each such unit that is the product of: (i) the MW quantity of capacity that the unit cleared in the Forward Capacity Auction associated with the Capacity Commitment Period; and (ii) the municipal utility's ownership entitlements in such unit. The CTRs allocated pursuant to this Section may be designated as self-supply quantities as described in Section III.13.1.6. Municipal utility ownership entitlements are set as shown in the table below and are not transferrable.

| | Millstone 3 | Seabrook | Stonybrook GT 1A | Stonybrook GT 1B | Stonybrook GT 1C | Stonybrook 2A | Stonybrook 2B | Wyman 4 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | |
| Danvers | 0.2627% | 1.1124% | 8.4569% | 8.4569% | 8.4569% | 11.5551% | 11.5551% | 0.0000% | | |
| Georgetown | 0.0208% | 0.0956% | 0.7356% | 0.7356% | 0.7356% | 1.0144% | 1.0144% | 0.0000% | | |
| Ipswich | 0.0608% | 0.1066% | 0.2934% | 0.2934% | 0.2934% | 0.0000% | 0.0000% | 0.0000% | | |
| Marblehead | 0.1544% | 0.1351% | 2.6840% | 2.6840% | 2.6840% | 1.5980% | 1.5980% | 0.2793% | | |
| Middleton | 0.0440% | 0.3282% | 0.8776% | 0.8776% | 0.8776% | 1.8916% | 1.8916% | 0.1012% | | |
| Peabody | 0.2969% | 1.1300% | 13.0520% | 13.0520% | 13.0520% | 0.0000% | 0.0000% | 0.0000% | | |
| Reading | 0.4041% | 0.6351% | 14.4530% | 14.4530% | 14.4530% | 19.5163% | 19.5163% | 0.0000% | | |
| Wakefield | 0.2055% | 0.3870% | 3.9929% | 3.9929% | 3.9929% | 6.3791% | 6.3791% | 0.4398% | | |
| Ashburnham | 0.0307% | 0.0652% | 0.6922% | 0.6922% | 0.6922% | 0.9285% | 0.9285% | 0.0000% | | |
| Boylston | 0.0264% | 0.0849% | 0.5933% | 0.5933% | 0.5933% | 0.9120% | 0.9120% | 0.0522% | | |
| Braintree | 0.0000% | 0.6134% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | |
| Groton | 0.0254% | 0.1288% | 0.8034% | 0.8034% | 0.8034% | 1.0832% | 1.0832% | 0.0000% | | |
| Hingham | 0.1007% | 0.4740% | 3.9815% | 3.9815% | 3.9815% | 5.3307% | 5.3307% | 0.0000% | | |
| Holden | 0.0726% | 0.3971% | 2.2670% | 2.2670% | 2.2670% | 3.1984% | 3.1984% | 0.0000% | | |
| Holyoke | 0.3194% | 0.3096% | 0.0000% | 0.0000% | 0.0000% | 2.8342% | 2.8342% | 0.6882% | | |
| Hudson | 0.1056% | 1.6745% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.3395% | | |
| Hull | 0.0380% | 0.1650% | 1.4848% | 1.4848% | 1.4848% | 2.1793% | 2.1793% | 0.1262% | | |
| Littleton | 0.0536% | 0.1093% | 1.5115% | 1.5115% | 1.5115% | 3.0607% | 3.0607% | 0.1666% | | |
| Mansfield | 0.1581% | 0.7902% | 5.0951% | 5.0951% | 5.0951% | 7.2217% | 7.2217% | 0.0000% | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Middleborough | 0.1128% | 0.5034% | 2.0657% | 2.0657% | 2.0657% | 4.9518% | 4.9518% | 0.1667% | | |
| North Attleborough | 0.1744% | 0.3781% | 3.2277% | 3.2277% | 3.2277% | 5.9838% | 5.9838% | 0.1666% | | |
| Pascoag | 0.0000% | 0.1068% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | |
| Paxton | 0.0326% | 0.0808% | 0.6860% | 0.6860% | 0.6860% | 0.9979% | 0.9979% | 0.0000% | | |
| Shrewsbury | 0.2323% | 0.5756% | 3.9105% | 3.9105% | 3.9105% | 0.0000% | 0.0000% | 0.4168% | | |
| South Hadley | 0.5755% | 0.3412% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | |
| Sterling | 0.0294% | 0.2044% | 0.7336% | 0.7336% | 0.7336% | 1.1014% | 1.1014% | 0.0000% | | |
| Taunton | 0.0000% | 0.1003% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | |
| Templeton | 0.0700% | 0.1926% | 1.3941% | 1.3941% | 1.3941% | 2.3894% | 2.3894% | 0.0000% | | |
| Vermont Public Power Supply Authority | 0.0000% | 0.0000% | 2.2008% | 2.2008% | 2.2008% | 0.0000% | 0.0000% | 0.0330% | | |
| West Boylston | 0.0792% | 0.1814% | 1.2829% | 1.2829% | 1.2829% | 2.3041% | 2.3041% | 0.0000% | | |
| Westfield | 1.1131% | 0.3645% | 9.0452% | 9.0452% | 9.0452% | 13.5684% | 13.5684% | 0.7257% | | |

Allocation of CTRs as described in this Section shall expire on December 31, 2040. If a unit listed in the table above retires prior to December 31, 2040, however, allocation of CTRs for such unit shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) For any CTRs specifically allocated pursuant to this Section that are not designated self-supply quantities for the Capacity Commitment Period, the municipal utility entitlement holder shall receive a credit reflecting the value of such remaining CTRs. The value of each remaining CTR shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located; and (ii) the remaining MW quantity. This value will be divided by the number of days in the month to derive a daily settlement value.

**III.13.7.5.5. Forward Capacity Market Net Charge Amount.**

The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charges; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund (for Capacity Commitment Periods beginning prior to June 1, 2022); and (d) any applicable export charges.

## III.15. Annual Capacity Market.

(a) Annual Capacity Market Overview.

The ISO shall administer an annual market for capacity (Annual Capacity Market) in accordance with the provisions of this Section III.15. For each one-year period from June 1 through May 31, starting with the period June 1, 2028 to May 31, 2029, for which Capacity Supply Obligations are assumed and payments are made in the Annual Capacity Market ("Capacity Commitment Period"), the ISO shall conduct an Annual Capacity Auction in accordance with the provisions of Section III.15.4 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Annual Capacity Auction, a resource must have Qualified Capacity resulting from the Annual Capacity Auction qualification process in accordance with the provisions of Sections III.15.2 and III.15.3. Obligations associated with the Annual Capacity Market may be traded during ISO-administered Monthly Reconfiguration Auctions and monthly bilateral transactions, in accordance with Section III.15.5 and Section III.15.6, respectively. The obligations of resources with Capacity Supply Obligations resulting from the Annual Capacity Auction, Monthly Reconfiguration Auctions, and monthly bilateral transactions are set forth in Section III.15.7. Payments and charges resulting from participation in the Annual Capacity Market, Monthly Reconfiguration Auctions, and bilateral transactions, as well as Capacity Performance Payments, are set forth in Section III.15.8. The publication of auction-related information is set forth in Section III.15.9.

(b) Capacity Auction Calendar.

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2028, and for each Capacity Commitment Period thereafter, the ISO shall publish a calendar of dates and deadlines for the administration of the Capacity Market, with the dates and deadlines being consistent for each Annual Capacity Auction cycle. The Capacity Auction Calendar shall include specific dates and deadlines for all such Capacity Market dates and deadlines defined in this Section III.15 and related Tariff provisions. The following defines several milestone dates and deadlines.

(1) the Qualification Data Submission Deadline for the Annual Capacity Auction shall occur during the month of February;

(2) the Capacity Demonstration Deadline for the Annual Capacity Auction shall occur during the month of April; and

(3) the Annual Capacity Auction shall occur during the month of May.

(c) Modification of Capacity Auction Calendar.

The ISO may, on a prospective basis, reasonably revise any date or deadline in the Capacity Auction Calendar with written notice of such revision to each Governance Participant in the manner specified in Section 17.11(b) of the Participants Agreement prior to the occurrence of the date or deadline being revised. In the event a Market Participant fails to meet a deadline in the Capacity Auction Calendar for submission of information or data, the ISO shall extend such deadline for that Market Participant upon receipt of an order from the Commission granting the Market Participant's request for a waiver of such deadline for good cause shown. In no event shall a date or deadline be extended, prospectively by the ISO or retroactively by filing of a Market Participant, should doing so interfere with the ISO's effective administration of the Capacity Market.

(d) Effectiveness for the 2028-2029 Capacity Commitment Period and Thereafter.

The provisions of this Section III.15 are effective for the Capacity Commitment Period that runs from June 1, 2028 through May 31, 2029 and all Capacity Commitment Periods thereafter. Unless otherwise expressly stated, the provisions of this Section III.15 are not applicable to the Forward Capacity Market. Section III.13, addressing the administration of the Forward Capacity Market, shall continue to be effective for Capacity Commitment Periods through May 31, 2028. Unless otherwise expressly stated, the provisions of Section III.13 are not applicable to the Annual Capacity Market, Monthly Reconfiguration Auctions and monthly bilateral transactions addressed in this Section III.15 of Market Rule 1.

**III.15.A. Non-Commercial Capacity Transition Rules.**

All Capacity Resources that are on critical path schedule monitoring pursuant to Section III.13.3 as of June 1, 2028 are subject to the provisions of this Section III.15.A.

The ISO shall monitor the Non-Commercial Capacity resource's compliance with its critical path schedule from the time the ISO approves the request until the resource achieves FCM Commercial Operation, is terminated pursuant to Section III.15.A.2.1, or withdraws from critical path schedule monitoring pursuant to Section III.15.A.2.3.

**III.15.A.1. Non-Commercial Capacity Resource Critical Path Schedule Reports.**

For each resource that is being monitored for compliance with its critical path schedule, the Lead Market Participant for that resource must provide a written critical path schedule report to the ISO no later than five Business Days after the end of each calendar quarter. If the Lead Market Participant does not provide a written critical path schedule report to the ISO by the fifth Business Day after the end of the calendar quarter, then the ISO shall issue a notice thereof to the Lead Market Participant. If the Lead Market Participant fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.15.A.2.1. Each critical path schedule report shall include a complete updated version of the critical path schedule as described in Section III.15.A.1.1 through Section III.15.A.1.3.

**III.15.A.1.1. Updated Critical Path Schedule.**

The critical path schedule report must include a complete updated version of the critical path schedule as described in Section III.15.A.1, dated contemporaneously with the submission of the critical path schedule report. The updated critical path schedule must clearly indicate if the Lead Market Participant is proposing to change any of the milestones or dates from the previously submitted version of the critical path schedule, and must include an explanation of any such proposed changes. In the critical path schedule report, the Lead Market Participant must also explain in detail any proposed changes to the project design and the potential impact of such changes on the amount of capacity the resource will be able to provide.

**III.15.A.1.2. Documentation of Milestones Achieved.**

(a) For all new resources (except for Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW,

which are discussed in Section III.15.A.1.2(b)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Lead Market Participant must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Major Permits**. For each major permit described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the permit was applied for and obtained as described in the critical path schedule. For permit applications, this documentation could include a dated copy of the permit application or cover letter requesting the permit. For approved permits, this documentation could include a dated copy of the approved permit or letter granting the permit from the permitting authority.

(ii) **Project Financing Closing**. The Lead Market Participant shall provide documentation showing that the sources of financing identified in the critical path schedule have committed to provide the amount of financing described in the critical path schedule. This documentation could include copies of commitment letters from the sources of financing.

(iii) **Major Equipment Orders**. For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the equipment was ordered as described in the critical path schedule. This documentation should include a copy of a dated confirmation of the order from the manufacturer or supplier. This documentation should confirm scheduled delivery dates consistent with milestone Section III.15.A.1.2(a)(v).

(iv) **Substantial Site Construction.** The Lead Market Participant shall provide documentation showing that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs.

(v) **Major Equipment Delivery**. For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the equipment was delivered to the project site and received as preliminarily acceptable as described in the critical path schedule. This documentation should include a copy of a dated confirmation of delivery to the project site.

(vi) **Major Equipment Testing.** For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the component was tested, including major systems testing as appropriate for the specific technology as described in the critical path schedule, and that the test results demonstrate the equipment's suitability to allow, in conjunction with other major components, subsequent operation of the project in accordance with the amount of capacity subject to critical path schedule monitoring in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning**. The Lead Market Participant shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity subject to critical path schedule monitoring. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Lead Market Participant is not required to provide documentation of Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) to the ISO as part of the ISO's critical path schedule monitoring. The ISO shall confirm that the resource has achieved Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) as described in the critical path schedule through the resource's compliance with the other relevant requirements of the Transmission, Markets and Services Tariff and the ISO New England System Rules.

(ix) **Transmission Upgrades**. The Lead Market Participant shall provide documentation showing that all interconnection facilities and upgrades identified for the project associated with the resource in a Transitional Cluster Study, Cluster Study, or Cluster Restudy (conducted pursuant to Section 7.5 of Schedule 22, Section 7.5 of Schedule 23, or Section 7.5 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff), or interconnection request or agreement under applicable state tariff, rules or procedures, have been completed.

(b) For Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Lead Market

Participant must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion**. The Lead Market Participant shall provide documentation showing the resource will be capable of providing its total offered demand reduction value as described in the New Demand Capacity Resource Qualification Package by the proposed Commercial Operation Date reported in the critical path schedule report.

(ii) **Additional Requirements**. For each customer and each prospective customer the Lead Market Participant shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Asset has been registered with the ISO, then the Lead Market Participant shall also provide the Asset identification number.

**III.15.A.1.3. Additional Relevant Information.**

The Lead Market Participant must include in the critical path schedule report any other information regarding the status or progress of the project or any of the project milestones that might be relevant to the ISO's evaluation of the feasibility of the project being built in accordance with the critical path schedule.

**III.15.A.2. Failure to Meet Critical Path Schedule.**

If the ISO determines that any critical path schedule milestone date has been missed, or if the Lead Market Participant proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.15.A.1), then the ISO shall consult with the Lead Market Participant to determine the impact of the missed milestone or proposed revision, and shall determine a revised date for the milestone and for any other milestones affected by the change. If a milestone date is revised for any reason, the ISO may require the Lead Market Participant to submit a written report to the ISO on the fifth Business Day of each month until the revised milestone is achieved detailing the progress toward meeting the revised milestone. If the Lead Market Participant does not provide a written critical path schedule report to the ISO on the fifth Business Day of a month, then the ISO shall issue a notice thereof to the Lead Market Participant. If the Lead Market Participant fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.15.A.2.1. Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.15.A.1.

**III.15.A.2.1. Termination of Critical Path Schedule Monitoring.**

If a Lead Market Participant fails to comply with the requirements of Sections III.15.A.1 or III.15.A.2, or if, as a result of milestone date revisions, the date by which a resource will have achieved all its critical path schedule milestones is more than two years after the beginning of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation, then the ISO, after consultation with the Lead Market Participant, shall have the right, through a filing with the Commission, to terminate the resource's status on critical path schedule monitoring, provided that, where a Lead Market Participant voluntarily withdraws its resource from critical path schedule monitoring in accordance with Section III.15.A.2.3 no filing with the Commission shall be necessary. Upon Commission ruling, the Lead Market Participant shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation. If in these circumstances, however, the ISO does not take steps to terminate the resource and instead permits the Lead Market Participant to continue on critical path schedule monitoring, such continuation shall be subject to the ISO's right to revoke that permission and to file with the Commission to terminate the resource, and subject to continued reporting by the Lead Market Participant in accordance with Section III.15.A.1.

**III.15.A.2.2. Termination of Interconnection Agreement.**

If the ISO terminates, or files with the Commission to terminate, a resource's ability to remain on critical path schedule monitoring, the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. The ISO shall also reduce the resource's assigned capacity interconnection service (or equivalent for resources not subject to the ISO Interconnection Procedures).

**III.15.A.2.3. Withdrawal from Critical Path Schedule Monitoring**.

A Lead Market Participant may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO.

**III.15.A.3. Financial Assurance.**

The financial assurance requirements for Designated FCM Participants offering Non-Commercial Capacity into the Forward Capacity Auction, as described in Section VII.B.2.b the ISO New England Financial Assurance Policy, shall continue to apply to all Capacity Resources that are subject to the provisions of this Section III.15.A.

Once a resource with Non-Commercial Capacity achieves commercial operation, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as a resource that has achieved Capacity Market Commercial Operation, as governed by the ISO New England Financial Assurance Policy.

If a Capacity Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited. Any financial assurance that is forfeited pursuant to Section III.15.A shall be used to reduce charges incurred by load in the relevant Capacity Zone.

**III.15.A.4. Demonstrating FCM Commercial Operation**

All Capacity Resources subject to the provisions of this Section III.15.A shall achieve commercial operation, for purposes of ending critical path schedule monitoring, in accordance with the FCM Commercial Operation requirements specified in Section III.13.3.8.

**III.15.A.5. Settlement of Qualification Process Cost Reimbursement Deposit.**

Upon the date on which the entire resource is no longer on critical path schedule monitoring, the ISO shall provide the Lead Market Participant with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff. All Capacity Resources that are subject to the provisions of this Section III.15.A shall be subject to the Forward Capacity Market payment and refund requirements as set forth in Section III.13.1.9.3.2 of the Tariff.

**III.15.1. Auction Demand Curves and Other Auction Inputs.**

**III.15.1.1. Annual Capacity Auction Demand Curves**.

The total amount of capacity cleared in the Annual Capacity Auction pursuant to Section III.15.4 shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the Capacity Zones modeled for the Annual Capacity Auction.

**III.15.1.1.1. System-Wide Capacity Demand Curve.**

The System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.15.1.1.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Capacity Auction Offer Price Cap.

**III.15.1.1.2. Import-Constrained Capacity Zone Demand Curves.**

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.15.1.1.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Capacity Auction Offer Price Cap.

**III.15.1.1.3. Export-Constrained Capacity Zone Demand Curves.**

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.15.1.1.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

**III.15.1.1.4. Capacity Demand Curve Scaling Factor.**

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

**III.15.1.2. Capacity Auction Offer Price Cap and the Cost of New Entry.**

**III.15.1.2.1. Calculation of Capacity Auction Offer Price Cap, CONE, and Net CONE.**

(a) The Capacity Auction Offer Price Cap shall be the greater of (i) 1.6 multiplied by Net CONE; and (ii) CONE. References in this Section III.15 and Sections III.A.21 and III.A.24 to the Capacity Auction Offer Price Cap shall mean the Capacity Auction Offer Price Cap for the Annual Capacity Auction associated with the relevant Capacity Commitment Period.

(b) To determine the CONE and Net CONE for the Annual Capacity Auctions associated with the Capacity Commitment Period beginning on June 1, 2028 and the Capacity Commitment Period beginning on June 1, 2029, the ISO shall make interim-year adjustments as described in Section III.15.1.2.2 to the following CONE and Net CONE calculated for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025:

(i) CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 was $12.400/kW-month.

(ii) Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 was $7.468/kW-month.

(c) The ISO shall recalculate CONE and Net CONE for the Annual Capacity Auction for the Capacity Commitment Period beginning on June 1, 2030. Thereafter, CONE and Net CONE shall be recalculated no less often than once every four years. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders, and the new values will be filed with the Commission prior to the Annual Capacity Auction in which the new value is to apply.

**III.15.1.2.2. Interim-Year Adjustments to CONE and Net CONE.**

(a) For years in which no full recalculation is performed pursuant to Section III.15.1.2.1, CONE and Net CONE shall be adjusted for each Annual Capacity Auction with the following updates to the capital

budgeting model used to calculate the CONE and Net CONE values set forth above in this Section III.15.1.2:

(1) Each line item associated with capital costs that is included in the capital budgeting model shall be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114).

(2) For each line item in (1) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the CONE and Net CONE values set forth in Section III.15.1.2.1. The value of each line item associated with capital costs in the capital budgeting model will be adjusted by the relevant multiplier.

(3) The energy and ancillary services offset values in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE, for each month of the Capacity Commitment Period to which the updated value will apply.

(4) The annual adjustment to CONE and Net CONE for the Annual Capacity Auction for the Capacity Commitment Period beginning June 1, 2028, shall use a cost of debt of 6.85% and a cost of equity of 13.80%. These values shall also be used for the Annual Capacity Auction for the Capacity Commitment Period beginning on June 1, 2029.

(5) If any of the values required for the calculations described in this Section III.15.1.2.2 are unavailable, then comparable values, prices or sources shall be used.

(b) The CONE and Net CONE values adjusted pursuant to this Section III.15.1.2.2 will be published on the ISO's website.

**III.15.2. Capacity Resource Qualification.**

Each resource, or portion thereof, must qualify as a Generating Capacity Resource, an Import Capacity Resource, a Demand Capacity Resource, or a Distributed Energy Capacity Resource. Each resource must be at least 100 kW in size to participate in an Annual Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of Section III.13 became effective. The summer period of a Capacity Resource's Seasonal Qualified Capacity Values shall be the months of June through September and the winter period shall be the months of October through May, except in the case of Demand Capacity Resources, where the summer period shall be the months of April through November and the winter period shall be the months of December through March.

This Section III.15.2 details the requirements of the qualification process for the Annual Capacity Auction, as well as certain requirements related to Monthly Reconfiguration Auctions and Capacity Supply Obligation Bilateral transactions. Data submission and demonstration requirements for resources that have never previously counted as capacity and seek to qualify to participate in an Annual Capacity Auction, are set forth in Section III.15.2.1. Data submission and demonstration requirements for resources that have never previously counted as capacity and seek to qualify to participate in a Monthly Reconfiguration Auction are set forth in Section III.15.2.2. Qualification requirements with respect to interconnection service are addressed in Section III.15.2.3. Qualification requirements with respect to resources that have previously counted as capacity and have materially changed are addressed in Section III.15.2.4. Following the Annual Capacity Auction's Qualification Data Submission Deadline, the ISO calculates and provides to Lead Market Participants Advisory Qualified Capacity Values for each Capacity Resource, per Section III.15.2.5. Lead Market Participants then have until the Capacity Demonstration Deadline to demonstrate that their Capacity Resources have achieved Commercial Operation, per Section III.15.2.6. Thereafter, the ISO calculates Seasonal Qualified Capacity Values for each Capacity Resource, per Section III.15.2.7, which values are subject to the challenge process addressed therein. Lead Market Participants are then permitted to submit Composite Offers in accordance with Section III.15.2.8, and load serving entities are permitted to submit self-supply designations in accordance with III.15.2.9. Final Qualified Capacity values for each Capacity Resource are calculated by the ISO one Business Day prior to the opening of the Annual Capacity Auction Offer Window in accordance with Section III.15.2.10. The publication of offer information during the qualification process and after the Annual Capacity Auction is addressed in Section III.15.2.11.

Resources seeking to qualify for an Annual Capacity Auction may be subject to buyer-side market power review and mitigation pursuant to Section III.A.21 and must abide by the applicable submission

requirements and timelines set forth therein prior to seeking to qualify for an Annual Capacity Auction. To the extent not already established for the purposes of the submission requirements of Section III.A.21.1.5, all capacity suppliers seeking to qualify for an Annual Capacity Auction must be Market Participants prior to the Qualification Data Submission Deadline. The Lead Market Participant for a resource participating in an Annual Capacity Auction may not change during the period beginning 15 Business Days prior to the opening of the Annual Capacity Auction Offer Window and ending with the posting of the results of the Annual Capacity Auction.

**III.15.2.1. Qualification Data Submission Requirements.**

**III.15.2.1.1. Qualification Data Submission Package.**

(a) For a resource that has not previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction to qualify as a Capacity Resource for participation in an Annual Capacity Auction, a Lead Market Participant must submit the following information to the ISO by the Qualification Data Submission Deadline, as applicable:

(i) the resource name;

(ii) the Lead Market Participant's contact information;

(iii) the date by which the resource is expected to complete its capacity demonstration pursuant to III.15.2.6(c) or to update its as-built data pursuant to III.15.2.6(d);

(iv) the resource address or location, and if available, asset identification number;

(v) whether the resource has ever previously had a Capacity Supply Obligation;

(vi) the location of the resource's interconnection;

(vii) the estimated Seasonal Qualified Capacity Values of the resource, as well as an estimate of any incremental Seasonal Qualified Capacity Values (in MW) (for Generating Capacity Resources and Import Capacity Resources);

(viii) the estimated total summer and winter demand reduction value (for Demand Capacity Resources and Distributed Energy Capacity Resources) or net injection capability values per facility (for Distributed Energy Capacity Resources);

(ix) a description of the resource, including (for Generating Capacity Resources and Import Capacity Resources) a general description of the resource's equipment configuration and a description of the resource technology type, and (for Demand Capacity Resources) a description of the resource's Demand Capacity Resource type and measure type, and (for Distributed Energy Capacity Resources) a description of the project and its configuration, including the types of generation and demand response composing the project, and (for

Generating Capacity Resources and Distributed Energy Capacity Resources comprising generation) a one-line diagram of the resource's configuration;

(x) for resources supported by an Internal Elective Transmission Upgrade, all unique project identifiers associated with the Internal Elective Transmission Upgrade;

(xi) for Generating Capacity Resources with a contract to export capacity from the New England Control Area during the Capacity Commitment Period, the interface over which the capacity will be exported and the contract associated with the export capacity;

(xii) Additional requirements for Import Capacity Resources, the interface over which the capacity will be imported and one of the following submissions documenting the source of the imported capacity, as further detailed in Section III.15.2.1.1.1: (i) documentation of a contract entered into before the Qualification Data Submission Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for one or more years encompassing the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iii) documentation for system-backed import capacity that the Import Capacity Resource will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load.

(xiii) Additional requirements for Demand Capacity Resources, as further detailed in Section III.15.2.1.1.2: resource technical and credit/financial contacts; Measurement and Verification Plan (for On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources); Load Zone and Dispatch Zone (for Active Demand Capacity Resources);

(xiv) Additional requirements for Distributed Energy Capacity Resources, as further detailed in Section III.15.2.1.1.3: expected nameplate capacity by technology type per facility; installation date of facilities that are part of the project and already constructed, installed, or in commercial operation; indication of whether the project elects Intermittent Power Resource treatment; resource technical and credit/financial contacts; Load Zone, Dispatch Zone and DRR Aggregation Zone;

(xv) Additional requirements for resources with capacity impacted by ambient air conditions between 90 degrees and 100 degrees, as further detailed in Section III.15.2.1.5; and

(xvi) Additional requirements for resources seeking ISO-estimated Seasonal Qualified Capacity Values, as further detailed in III.15.2.6(d): the Qualification Data Submission Package shall satisfy the technical data requirements associated with such resources and be supplemented with the as-built status of the resource on the date of the relevant Capacity Demonstration Deadline.

(b) By submitting the required qualification information, the Lead Market Participant certifies that a Capacity Offer from the resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 of Section II of the Tariff.

(c) The ISO may waive the submission of any information not required for evaluation of the resource.

**III.15.2.1.1.1. Additional Import Capacity Resource Requirements.**

Import Capacity Resources must be backed by one or more External Resources or by an external Control Area for the duration of the relevant Capacity Commitment Period. An external demand resource may not be an Import Capacity Resource. External nodes shall be established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff. For the purposes of the qualification process, all Import Capacity Resources shall be treated as if they had never previously participated as capacity and must submit the materials described pursuant to this Section III.15.2.1.1 for each Capacity Commitment Period for which the Import Capacity Resource seeks to qualify capacity. Import Capacity Resources backed by an External Control Area that does not have a Coordination Agreement with the ISO shall be ineligible to participate in the Annual Capacity Market. No single Import Capacity Resource may qualify capacity in excess of the external interface limits as described in Section III.12.10.

An Elective Transmission Upgrade with Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall have its external node modeled in the Annual Capacity Auction after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Annual Capacity Auction qualification requirements of this Section III.15.2.1 and demonstration requirements of III.15.2.6. The Qualified Capacity of all Import Capacity Resources associated with an Elective Transmission Upgrade shall not exceed the Elective Transmission Upgrade's Capacity Network Import Capability.

Capacity Offers for Import Capacity Resources shall be subject to rationing except for Capacity Offers priced above the Capacity Offer Price Threshold for Import Capacity resources associated with an Elective Transmission Upgrade, which must obtain a Capacity Supply Obligation or not in whole unless the Capacity Offer indicated that it may be rationed as described in III.15.4.1.

**III.15.2.1.1.1.1. Imports Backed by External Resources.**

If the Import Capacity Resource will be backed by one or more External Resources, the Lead Market Participant shall submit a description of how the Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify. The description must indicate specifically which External Resources will back the Import Capacity Resource during the Capacity Commitment Period and contain the relevant historical performance data for each resource. If those External Resources are not owned or controlled directly by the Lead Market Participant, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

**III.15.2.1.1.1.2. Imports Backed by an External Control Area.**

If the Import Capacity Resource will be backed by an external Control Area, the Lead Market Participant shall submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the Import Capacity Resource.

**III.15.2.1.1.1.3. Imports Crossing Intervening Control Areas.**

Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) for imports crossing a single intervening Control Area, the Lead Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the Qualification Data Submission Deadline, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing; (2) for imports crossing more than one intervening Control Area, in addition to the requirements above, the Lead Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals,

by the Qualification Data Submission Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load; and (3) the Lead Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

**III.15.2.1.1.2. Additional Demand Capacity Resource Requirements.**

A Demand Capacity Resource may be an Active Demand Capacity Resource, On-Peak Demand Capacity Resource, or Seasonal Peak Demand Capacity Resource, and may include an end-use customer facility with a Net Supply Capability of 5 MW or more only if the facility's Net Supply Capability does not exceed its Maximum Facility Load. Demand Capacity Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Capacity Resource. Demand Capacity Resources are not permitted to submit a Capacity Offer to import into or export out of the New England Control Area.

For a resource, or portion thereof, that never previously obtained a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction to qualify as an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource for the Capacity Commitment Period beginning June 1, 2028, the measure or measures contained in the resource must not have been in-service prior to June 1, 2024. For a resource, or portion thereof, that never previously obtained a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction to qualify as an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource in the Annual Capacity Auction or Monthly Reconfiguration Auction, as relevant, for or during the Capacity Commitment Period beginning June 1, 2029, and all Capacity Commitment Periods thereafter, the measure or measures contained in the resource must have been placed in-service or previously qualified as capacity no more than six months before the prior Annual Capacity Auction's Capacity Demonstration Deadline.

**III.15.2.1.1.2.1. Measurement and Verification of Demand Capacity Resources.**

(a) To demonstrate the demand reduction value of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, the Lead Market Participant of such a resource participating in the Annual Capacity Auction, Capacity Supply Obligation Bilaterals, or Monthly Reconfiguration Auctions shall submit to the ISO Measurement and Verification Documents in accordance with this Section III.15.2.1.1.2.1 and the ISO New England Manuals. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.15.2.1.1.2.1 and the ISO New England Manuals.

(b) Measurement and Verification Documents must demonstrate both availability and performance of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource in reducing demand coincident with Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours such that the reported monthly demand reduction value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manuals and ISO New England Operating Procedures. The Measurement and Verification Documents shall: (1) serve as the basis for the claimed demand reduction value of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource; (2) document the measurement and verification performed to verify the achieved demand reduction value of the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource; and (3) contain a projection of the On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's demand reduction value for each month of the Capacity Commitment Period and, for those Demand Capacity Resources composed of energy efficiency measures, over the expected Measure Lives. An On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours. If an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource includes Distributed Generation, the Measurement and Verification Documents must describe the individual metering or metering protocol used to monitor and verify the output of the Distributed Generation, consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals.

(c) The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Annual Capacity Auction qualification process, as described in this Section III.15.2.1.1.2.1, and monthly Measurement and Verification data submitted during the Capacity Commitment Period. The monthly Measurement and Verification data shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan.

Such monthly Measurement and Verification data shall document the Lead Market Participant's total demand reduction value from both eligible pre-existing measures and new measures, and the Lead Market Participant's total demand reduction value from both eligible pre-existing measures and new measures, for all measures in operation as of the end of the previous month. The monthly Measurement and Verification data shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Lead Market Participants. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

(d) Lead Market Participants for On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources shall submit no less frequently than once per year, a statement certifying that the Demand Capacity Resource for which the Lead Market Participant is requesting compensation continues to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than ten Business Days before the Qualification Data Submission Deadline.

(e) For On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources comprising customer facilities with greater than or equal to 10 kW of demand reduction value per facility, Lead Market Participants shall maintain records of retail customers served, including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly demand reduction values. For On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources targeting customer facilities with under 10 kW of demand reduction value per facility, the Lead Market Participant shall maintain records as described above for customer facilities with greater than or equal to 10 kW of demand reduction value per facility, or shall maintain records of aggregated demand reduction values and measures installed by Load Zone and meter domain. Lead Market Participants shall maintain such records until the end of the Measure Life, or until the Demand Capacity Resource is retired or deactivated from the Annual Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

(f) The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Annual Capacity Auction qualification

process as described in Section III.15.2 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Lead Market Participant to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

**III.15.2.1.1.3. Additional Distributed Energy Capacity Resource Requirements.**

(a) Distributed Energy Capacity Resources. A facility connected at a point of interconnection that is 5 MW or greater cannot be a part of a Distributed Energy Capacity Resource. A Distributed Energy Capacity Resource comprises one or more Distributed Energy Resource Aggregations located in a single Capacity Zone and a single DRR Aggregation Zone, except that (a) a Settlement Only Distributed Energy Resource Aggregation may not participate in a Distributed Energy Capacity Resource with any other type of Distributed Energy Resource Aggregation, and (b) an end-use customer facility participating as part of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource with measures other than Energy Efficiency may not participate in a Distributed Energy Capacity Resource. Distributed Energy Capacity Resources are not permitted to submit a Capacity Offer to import into or export out of the New England Control Area. For purposes of this Section III.15.2.1.1.3: (i) if a facility is expected to interconnect at a point of interconnection, its net injection capability is the generation capability of the installed generation technology at the point of interconnection; (ii) if a facility is expected to interconnect at a Retail Delivery Point and does not plan to participate in the aggregation as a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation, the net injection capability is the lesser of the generation less the load profile measured at the location of the end-use customer meter or the amount the facility is contractually able to inject.

(b) Demand Response Resource in Distributed Energy Capacity Resources. If the Distributed Energy Capacity Resource includes Demand Response Resources, the completed Qualification Data Submission Package shall include the following additional information: the estimated summer and winter demand reduction values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses); the estimated total summer and winter demand reduction value of the Demand Response Resource (which must be consistent with the baseline calculation methodology in Section

III.8.2); and supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated demand reduction values.

(c) Net Injection of 5 MW or Greater. If the Distributed Energy Capacity Resource contains a Distributed Energy Resource Aggregation with a facility with net injection of 5 MW or greater at a Retail Delivery Point, then the completed Qualification Data Submission Package for such a resource shall include the following additional information: the Pnode and service address at which the end-use facility is located; nameplate MW and net injection capability; non-coincident peak load (MW) of the facility without generation; technology type; and the Market Participant's portion of generation requested to be included as Qualified Capacity.

(d) Net Injection Greater Than or Equal to 1 MW and less than 5 MW. If the Distributed Energy Capacity Resource contains a Distributed Energy Resource Aggregation with a facility that has net injection capability at the point of interconnection of 1 MW or greater and less than 5 MW, then the completed Qualification Data Submission Package for such a facility shall include the following additional information: distribution bus; technology type; nameplate MW; one-line diagram of the plant and station facilities, including any known transmission facilities; if the facility is intermittent, the requested contribution of Qualified Capacity and supporting site-specific data; if an interconnection agreement is required under state requirements, the date when the interconnection request was submitted and the status of that interconnection request.

**III.15.2.1.2. Market Power Review.**

Lead Market Participants seeking to qualify a Capacity Resource that has not previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or that is otherwise treated as if it had never done so pursuant to this Section III.15.2, must comply with the market power review provisions of Section III.A.21 by the Annual Capacity Auction Qualification Data Submission Deadline.

**III.15.2.1.3. Capacity Commitment Period Election.**

For the Annual Capacity Auctions for the 2028-2029, 2029-2030 and 2030-2031 Capacity Commitment Periods, a Lead Market Participant that has made the election in Section III.13.1.1.2.2.4 of the Forward Capacity Market rules with respect to a Capacity Resource must specify by the Qualification Data Submission Deadline whether it elects to continue to have the associated Capacity Supply Obligation and Capacity Clearing Price apply in Annual Capacity Auctions for the balance of the period permitted for

such Capacity Resource pursuant to Section III.13.1.1.2.2.4. Should a Lead Market Participant elect to terminate Section III.13.1.1.2.2.4 treatment for its Capacity Resource, it may not re-elect such treatment for any future Annual Capacity Auctions.

A Lead Market Participant that has made the election in Section III.13.1.1.2.2.4 of the Forward Capacity Market rules with respect to a Capacity Resource which has not achieved Capacity Market Commercial Operation as defined in Section III.15.2.6 of Market Rule 1 may not participate in the Annual Capacity Auction for the 2028-2029 Capacity Commitment Period and shall not have the previously elected Capacity Supply Obligation and Capacity Clearing Price apply for the 2028-2029 Capacity Commitment Period. Should such resource achieve Capacity Market Commercial Operation in time for participation in the Annual Capacity Auction for the 2029-2030 Capacity Commitment Period, or the Annual Capacity Auction for the 2030-2031 Capacity Commitment Period, it may elect to have the Capacity Supply Obligation and Capacity Clearing Price it received pursuant to Section III.13.1.1.2.2.4 apply for the balance of the period permitted for such Capacity Resource pursuant to Section III.13.1.1.2.2.4, and in no event after the Annual Capacity Auction for the 2030-2031 Capacity Commitment Period.

**III.15.2.1.4. Material Deficiency in Data Submission.**

In its review of a Lead Market Participant's data submission under this Section III.15.2.1, the ISO may consult with the Lead Market Participant, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO determines that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Lead Market Participant may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

In the event the ISO determines that a Lead Market Participant's data submission under Section III.15.2.1 is materially deficient, it shall notify the participant of such deficiencies at least ten Business Days prior to publication of the Advisory Seasonal Qualified Capacity Values, and the Lead Market Participant shall have five Business Days from the date of notification to cure the deficiencies. Should a Lead Market Participant fail to cure such deficiencies by the end of the cure period, it shall not be permitted to participate in the Annual Capacity Auction. In the event of such a rejection, the ISO shall provide the

Lead Market Participant with a written explanation of the reason for the rejection within ten Business Days of the close of the cure period.

**III.15.2.1.5. Additional Qualification Requirements for Ambient Air Condition Impacts.**

In the Qualification Data Submission Package, a Lead Market Participant may submit documentation indicating that a portion of its resource's capacity will not be physically available due to an ambient air condition. The size of such ambient air condition is calculated as the difference between the summer Qualified Capacity at 90 degrees and the rating of the resource at 100 degrees. The ISO shall verify during the qualification process the size of the ambient air condition.

**III.15.2.2. Monthly Reconfiguration Auction Qualification.**

For a resource that has not previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction to qualify as a Capacity Resource for the purpose of participation in a Monthly Reconfiguration Auction pursuant to Section III.15.5 or bilateral activities pursuant to Section III.15.6, prior to the Capacity Demonstration Deadline for the relevant month a Lead Market Participant must: (1) submit the Qualification Data Submission Package as described in Section III.15.2.1 (except for the information described at Section III.15.2.1.2) by the Capacity Demonstration Deadline for the relevant month, except that an Import Capacity Resource or a Resource seeking ISO-estimated Seasonal Qualified Capacity Values pursuant to Section III.15.2.6(d) must submit its Qualification Data Submission Package 30 calendar days prior to the Capacity Demonstration Deadline; and (2) complete a capacity demonstration pursuant to Section III.15.2.6.

**III.15.2.3. Deliverability Review.**

A Generating Capacity Resource, Active Demand Capacity Resource, Import Capacity Resource associated with an External Elective Transmission Upgrade, and Distributed Energy Capacity Resource must satisfy the deliverability review requirements described in this Section III.15.2.3 in order to qualify capacity for participation in an Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction above the deliverability value associated with the resource's qualification for any previous Forward Capacity Auction, Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction. None of the provisions of this Section III.15.2, supersedes, replaces, or satisfies any of the requirements of Schedules 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder.

**III.15.2.3.1. Deliverability Review for Capacity Resources Associated with Generating Facilities or External Elective Transmission Upgrades Subject to Schedule 22, 23, or 25 of Section II of the Tariff.**

A Generating Facility or External Elective Transmission Upgrade subject to Schedules 22, 23 or 25 of Section II of the Tariff must complete the applicable interconnection processes set forth therein and have been assigned, as applicable, either Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service, as necessary to support the delivery of the associated Capacity Resource's Qualified Capacity.

**III.15.2.3.2. Deliverability Review for Capacity Resources Associated with Resources Not Subject to Schedule 22, 23, or 25 of Section II of the Tariff.**

For a Generating Capacity Resource, Active Demand Capacity Resource, or Distributed Energy Capacity Resource not subject to Schedules 22, 23, or 25 of Section II of the Tariff, the ISO shall perform a deliverability review based on: (1) the information provided in the resource's Qualification Data Submission Package; and (2) the results of the ISO's most recent deliverability analysis, performed consistent with the criteria and conditions conducted as described in the ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that such a resource cannot deliver any of the requested incremental capacity, then the resource or incremental portion thereof shall not qualify for participation in the Capacity Market as reflected in the Seasonal Qualified Capacity Values issued pursuant to Section III.15.2.7; otherwise, the ISO shall determine that the requested Qualified Capacity of the Capacity Resource is deliverable, and the Capacity Resource shall be eligible to continue to proceed with the remainder of the processes described in this Section III.15.2.

**III.15.2.4. Resources Previously Counted as Capacity.**

Resources that have previously counted as capacity shall, for the purposes of Section III.15.2, be treated as if they had never previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction if: (1) there is a material change to the Capacity Resource as described in III.15.2.4.1, or (2) if a deactivated or retired resource seeks to re-enter the Capacity Market pursuant to III.15.2.4.2.

**III.15.2.4.1. Material Change to a Capacity Resource.**

(a) A Lead Market Participant that materially changes a Capacity Resource that has previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or plans to do so prior to the relevant Capacity Demonstration Deadline, may, by the relevant Qualification Data

Submission Deadline or monthly Capacity Demonstration Deadline, inform the ISO of that material change, update the information provided under Section III.15.2.1.1 to reflect the change to the Capacity Resource, and demonstrate its updated Commercial Capacity pursuant to Section III.15.2.6. The updated Qualified Capacity of the resource, accounting for the change, shall be calculated in accordance with Section III.15.3.1 for the subsequent Annual Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral. The Seasonal Qualified Capacity of a Capacity Resource that notifies the ISO of a material change but does not demonstrate pursuant to III.15.2.6 shall remain unmodified until demonstration of the material change occurs.

(b) For purposes of this Section III.15.2.4, a material change to a Capacity Resource is a change to the design or operating characteristics of the resource, including its interconnection facilities, that may have a significant effect on the reliability or operating characteristics associated with the Capacity Resource, and shall include, but not be limited to, changing the resource technology type, making a change to the Capacity Resource that increases or decreases the resource's Annual Qualified Capacity by greater than the lesser of 5 MW or 10 percent, or any change to the resource that requires a material modification to its interconnection agreement. No less than 30 calendar days prior to the Qualification Data Submission Deadline or Monthly Capacity Demonstration Deadline, as relevant, a Lead Market Participant may request, and the ISO shall within 20 calendar days provide, a determination regarding whether a change qualifies as a material change to a Capacity Resource pursuant to this Section III.15.2.4 and requires submission of the materials required pursuant to Section III.15.2.1.1.

**III.15.2.4.2. Treatment of Previously Deactivated or Retired Resources.**

In order to qualify for participation in the Capacity Market, a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) must: (1) have reached its deactivation date and reduced its Capacity Network Resource Capability pursuant to Section II.48.3; (2) if the resource was compensated for delaying deactivation through a Commission-approved cost-of-service agreement, have refunded to the ISO all costs subject to refund under the claw-back provision set forth in Section II.54.1; and (3) have satisfied the provisions of Section III.15.2, including submission of the Qualification Data Submission Package described in Section III.15.2.1 and completed the capacity interconnection service requirements described in Section III.15.2.3, as if the resource had never previously received a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction.

**III.15.2.5. Calculation of Advisory Qualified Capacity Values.**

Following the Qualification Data Submission Deadline, by a date in the month of February published on the Capacity Auction Calendar, the ISO shall calculate and provide to Lead Market Participants summer and winter Advisory Qualified Capacity Values for each resource that has met the data submission requirements in Section III.15.2.1. The Advisory Qualified Capacity Values of any resource that has not previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or is otherwise treated as if it had not done so, shall equal its demonstrated Commercial Capacity determined in accordance with Section III.15.2.6; except that in the event that a resource has not yet demonstrated a portion of its Commercial Capacity, its Advisory Qualified Capacity Values shall equal the sum of its Commercial Capacity and the estimated incremental Seasonal Qualified Capacity Values of the resource as submitted pursuant to Section III.15.2.1. For all other resources, the Advisory Qualified Capacity Values shall equal the Capacity Resource's summer and winter Qualified Capacity as calculated pursuant to Section III.15.3.

During the period beginning with the ISO's issuance of Advisory Qualified Capacity Values and ending with the conclusion of the Annual Capacity Auction, any change to a capacity resource or the information submitted in a Qualification Data Submission Package shall not impact the resource's Seasonal Qualified Capacity Values for that Annual Capacity Auction unless the change has already been accounted for in the submitted Qualification Data Submission Package, or is made pursuant to Section III.15.2.1.4 or Section III.15.2.7.

**III.15.2.6. Capacity Commercial Operation Demonstration Requirement.**

To participate in an Annual Capacity Auction, Monthly Reconfiguration Auctions, or a Capacity Supply Obligation Bilateral transaction, a Capacity Resource must first demonstrate that its capacity is commercially operational by meeting the demonstration requirements in this Section III.15.2.6 by the applicable Capacity Demonstration Deadline. A resource that meets the demonstration requirements of this Section III.15.2.6 shall be deemed to have achieved Capacity Market Commercial Operation.

(a) Demonstration must be completed (i) prior to a Capacity Resource's initial participation in the Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction, and (ii) when a Capacity Resource that has previously received a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction materially changes or reactivates pursuant to Section III.15.2.4.

(b) The Capacity Demonstration Deadline for each Annual Capacity Auction shall be during the month of April preceding the relevant Annual Capacity Auction, as published on the Capacity Auction

Calendar; for each Monthly Reconfiguration Auction and Capacity Supply Obligation Bilateral window, the Capacity Demonstration Deadline shall precede the relevant Obligation Month by approximately two weeks, as published on the Capacity Auction Calendar.

(c) To demonstrate commercial capacity, a resource must perform an audit by the relevant Capacity Demonstration Deadline, using the following audit requirements:

(i) For Generating Capacity Resources that are not Intermittent Power Resources, each Generator Asset must perform an Establish Claim Capability Audit pursuant to Section III.1.5.1.2, provide the data described in ISO New England Operating Procedure No. 23, and have its audit value become effective pursuant to Section III.1.5.1.2(d)(iv).

(ii) For Generating Capacity Resources that are Intermittent Power Resources, each Generator Asset must perform a Seasonal Claim Capability Audit pursuant to Section III.1.5.1.3, provide the data described in ISO New England Operating Procedure No. 23, and have its audit value become effective pursuant to Section III.1.5.1.3(i).

(iii) For Active Demand Capacity Resources, each Demand Response Asset must perform a Seasonal DR Audit pursuant to III.1.5.1.3.1, as specified by season in III.15.7.1.5.3(c), requested by the Lead Market Participant, and have its audit value become effective pursuant to Section III.1.5.1.3.1(m).

(iv) For Demand Capacity Resources that are not Active Demand Capacity Resources, each Demand Capacity Resource must perform a Passive DR Audit pursuant to III.15.7.1.5.4, as specified by season in III.15.7.1.5.3(c), at the request of the Lead Market Participant, and have its audit value become effective pursuant to Section III.15.7.1.5.4(f).

(v) For Distributed Energy Capacity Resources, each asset comprising the Distributed Energy Capacity Resource must meet the demonstration requirement in sub-sections (i) through (iii) above for its corresponding asset type.

(vi) For Import Capacity Resources, demonstration is achieved through provision of performance data in the resource's Qualification Data Submission Package in accordance with Section III.15.2.1, except that Import Capacity Resources associated with an external Elective

Transmission Upgrade must demonstrate the ability to transfer power between regions pursuant to Schedule 25, Article 6.

(d) For those resources identified in Sections III.15.2.6(c)(ii), III.15.2.6(c)(iv), and III.15.2.6(c)(v) providing asset-level meter-based performance data by the Capacity Demonstration Deadline that is, as determined by the Lead Market Participant, of insufficient duration to establish accurate Seasonal Qualified Capacity Values, or for a period inconsistent with the audit described in Section III.15.2.6(c), the Lead Market Participant may request that the ISO determine Seasonal Qualified Capacity Values based on the lesser of: (1) the Seasonal Qualified Capacity Values requested for qualification by the Lead Market Participant; or (2) the Seasonal Qualified Capacity Values estimated by the ISO. In no instance shall the Seasonal Qualified Capacity Values developed pursuant to this Section III.15.2.6(d) exceed a resource's seasonal Capacity Network Resource Interconnection Service, or its equivalent.

The ISO-estimated Seasonal Qualified Capacity Values shall be based on technical data requirements for recently commercial resources identified in the Qualification Data Submission Package. The Qualification Data Submission Package of resources seeking ISO-estimated Seasonal Qualified Capacity Values shall include a description of the as-built status of the resource at time of submission, including whether the resource is fully or partially operational. For those resources seeking ISO-estimated Seasonal Qualified Capacity Values, the Qualification Data Submission Package must be submitted to the ISO by the Lead Market Participant by the Qualification Data Submission Deadline for the Annual Capacity Auction, or 30 days prior to the relevant monthly Capacity Demonstration Deadline, with the submission updated at the time of the Capacity Demonstration Deadline to reflect the as-built status of the resource. Resources satisfying the provisions of this Section III.15.2.6(d) shall be deemed to have demonstrated Commercial Capacity.

Resources seeking ISO-estimated Seasonal Qualified Capacity Values that have completed the relevant audit described in III.15.2.6(c) for only one season may elect to use the ISO-estimated Seasonal Qualified Capacity Values for one or both seasons. The ISO-estimated Seasonal Qualified Capacity Values may constitute a resource's Seasonal Qualified Capacity Value for up to one year after issuance, but shall be valid for no longer than one year after a resource becomes fully operational. A Lead Market Participant may request replacement of ISO-estimated Seasonal Qualified Capacity Values once the relevant seasonal audit has been completed.

**III.15.2.7. Seasonal Qualified Capacity Values and Challenge Process.**

(a) Following the April Capacity Demonstration Deadline, for each Capacity Resource qualified to participate in an Annual Capacity Auction, the ISO shall notify the Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity, calculated in accordance with Section III.15.3, and the Load Zone in which the resource is located. This notification will be provided by the Seasonal Qualified Capacity Notification Date specified in the Capacity Auction Calendar.

(b) If the Lead Market Participant believes that the ISO has made a mathematical error in calculating the summer Qualified Capacity or winter Qualified Capacity for a Capacity Resource, then the Lead Market Participant must notify the ISO within five calendar days of the Seasonal Qualified Capacity Notification Date.

(c) If a Capacity Resource's summer Qualified Capacity has been subject to a significant decrease pursuant to Section III.15.3.6, the Lead Market Participant may submit a restoration plan in accordance with Section III.15.3.6(b) within five calendar days of the Seasonal Qualified Capacity Notification Date.

(d) The ISO shall notify the Lead Market Participant of the outcome of any challenge submitted under (b) above or of its determination regarding the sufficiency of a restoration plan submitted under (c) above, by the date specified in the Capacity Auction Calendar for such responses. In assessing the sufficiency of a restoration plan, the ISO shall determine whether the plan provides sufficient information to support the reasonable likelihood of the resource providing capacity consistent with its summer Qualified Capacity value by the start of the Capacity Commitment Period.

**III.15.2.8. Offers Composed of Separate Resources (Composite Offers).**

Separate resources seeking to participate together in an Annual Capacity Auction shall submit a Composite Offer Form no later than the Composite Offer Deadline, which shall be approximately two business days prior to the auction as specified in the Capacity Auction Calendar, with the exception that Distributed Energy Capacity Resources may not participate in composite offers. Composite offers may not be modified or withdrawn after the Composite Offer Deadline. Composite offers must meet the following conditions:

(a) In all months of the summer period of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources combined meet the amount of the offer in all

months of the winter period; and (ii) to combine for a month, that month must be a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of a composite offer must qualify in accordance with all of the provisions of Section III.15.2 applicable to that resource type. A composite offer participates in the Annual Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period.

(c) The summer Qualified Capacity of a composite offer shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.15.3.7 shall apply, even where one or more of the resources that are part of the offer composed of separate resources is an Intermittent Power Resource. If the winter capacity of the composite offer in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) Composite offers are subject to the locational restrictions specified in the following table:

| | | **Location of Summer Resource** | | | |
|---|---|---|---|---|---|
| | | Import-Constrained Capacity Zone | Rest-of-Pool Capacity Zone | Export-Constrained Capacity Zone | Nested Export-Constrained Capacity Zone |
| **Location of Winter Resource** | Import-Constrained Capacity Zone | Eligible (within same Capacity Zone) | Eligible | Eligible | Eligible |
| | Rest-of-Pool Capacity Zone | Ineligible | Eligible | Eligible | Eligible |
| | Export-Constrained Capacity Zone | Ineligible | Ineligible | Eligible (within same Capacity Zone) | Eligible (within same Capacity Zone where nested export-constrained Capacity Zone is located) |

| | | | | | |
|---|---|---|---|---|---|
| | Nested Export-Constrained Capacity Zone | Ineligible | Ineligible | Ineligible | Eligible (within same Capacity Zone) |

**III.15.2.9. Self-Supplied Capacity.**

Where a load serving entity elects to designate all or a portion of its Capacity Load Obligation as self-supplied, the load serving must make such designation to the ISO during the self-supply designation window, as published in the Capacity Auction Calendar on the ISO's website. The load serving entity's designation shall specify the MW amount and Lead Market Participant providing the self-supplied capacity. During the Annual Capacity Auction Offer Window, the Lead Market Participant supplying such capacity shall confirm the load serving entity's self-supply designation by specifying each Self-Supplied Capacity Resource and the MW amount of self-supplied capacity in its Capacity Offer. A Generating Capacity Resource or an Import Capacity Resource may be designated as a Self-Supplied Capacity Resource. A Distributed Energy Capacity Resource may only designate its net injection capability as a Self-Supplied Capacity Resource. All self-supplied capacity shall be subject to the eligibility and locational requirements in this Section III.15.2.9. If designated as a Self-Supplied Capacity Resource the resource will clear in the Annual Capacity Auction as described in Section III.15.4 and, with the exception of demand programs for Self-Supplied Capacity Resources, shall offset an equal amount of the load serving entity's Capacity Load Obligation in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Capacity Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.15.2. All designations as a Self-Supplied Capacity Resource in the Annual Capacity Auction qualification process are binding.

**III.15.2.9.1. Self-Supplied Capacity Eligibility.**

Where all or a portion of a resource is designated as a Self-Supplied Capacity Resource, it shall also maintain its status as a Generating Capacity Resource, Import Capacity Resource, or Distributed Energy Capacity Resource and must satisfy the Annual Capacity Auction qualification process requirements set forth in the remainder of Section III.15.2 applicable to that resource type, in addition to the requirements of this Section III.15.2.9.1. Where a Capacity Offer composed of separate resources is submitted for a Self-Supplied Capacity Resource, all of the requirements and deadlines specified in Section III.15.2.8 shall apply to that offer, in addition to the requirements of this Section III.15.2.9. The total quantity of capacity that a load serving entity designates as self-supplied capacity

may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period, which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied Capacity Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

**III.15.2.9.2. Locational Requirements for Self-Supplied Capacity Resources.**

In order to participate in the Annual Capacity Auction as a Self-Supplied Capacity Resource for a load in an import-constrained Capacity Zone, the Self-Supplied Capacity Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied Capacity Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Annual Capacity Auction as a Self-Supplied Capacity Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied Capacity Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

**III.15.2.10. Publication of Annual Qualified Capacity Values for Annual Capacity Auction.**

The ISO shall provide Annual Qualified Capacity values to Lead Market Participants of each Capacity Resource participating in an Annual Capacity Auction one business day before the opening of the Annual Capacity Auction Offer Window.

**III.15.2.11. Publication of Offer Information.**

(a) For each Capacity Offer, the quantity and Load Zone (or interface, as applicable) in which the resource is located will be published to the ISO's website no later than 15 days after the Annual Capacity Auction is conducted.

(b) For Capacity Offers from Import Capacity Resources, the name of submitter, quantity, and interface shall be published to the ISO's website no later than 15 days after the Annual Capacity Auction is conducted.

(c) The name of each Lead Market Participant submitting Capacity Offers, as well as the number of Capacity Offers submitted by each Lead Market Participant, shall be published to the ISO's website no later than 15 calendar days after the issuance of Advisory Qualified Capacity Values. Authorized Persons

of Authorized Commissions will be provided confidential access to full information about posted Capacity Offers upon request pursuant to Section 3.3 of the ISO New England Information Policy.

**III.15.3. Capacity Resource Accreditation.**

Pursuant to the provisions of this Section III.15.3, the ISO shall determine a summer Qualified Capacity, a winter Qualified Capacity, an Annual Qualified Capacity and, where applicable, a Monthly Qualified Capacity for each Generating Capacity Resource, Import Capacity Resource, Demand Capacity Resource, and Distributed Energy Capacity Resource. A Capacity Resource's Seasonal Qualified Capacity Values shall not exceed its seasonal Capacity Network Resource Interconnection Service or equivalent, or Capacity Network Import Interconnection Service, as applicable. Qualified Capacity for resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall not exceed the resource's highest previously received Capacity Supply Obligation unless the resource has demonstrated and qualified the additional capacity pursuant to Section III.15.2.4.1.

Qualified Capacity values for resources that have never previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall be calculated pursuant to Section III.15.3.1. Qualified Capacity for resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall be calculated pursuant to Sections III.15.3.2 through III.15.3.5.

**III.15.3.1. Qualified Capacity for Resources Never Previously Counted as Capacity.**

**III.15.3.1.1. Resources Never Previously Counted as Capacity**.

The summer and winter Qualified Capacity of a Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or is otherwise treated as such pursuant to the terms of this Section III.15, shall be determined in accordance with the capacity demonstration requirements set forth in Section III.15.2.6, as specified below.

To determine the Seasonal Qualified Capacity Values of a Generating Capacity Resource that is not an Intermittent Power Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant to Section III.15.2.6(c)(i), the ISO shall use the Section III.1.5.1.2(c) audit results. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3 and III.15.3.2.4, respectively.

To determine the Seasonal Qualified Capacity Values of a Generating Capacity Resource that is an Intermittent Power Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant Section III.15.2.6(c)(ii), the ISO shall use the Section III.1.5.1.3 audit results. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3 and Section III.15.3.2.4, respectively.

To determine the Seasonal Qualified Capacity Values of an Active Demand Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(iii), the ISO shall use the Section III.1.5.1.3.1 audit results. To determine the Seasonal Qualified Capacity Values of a Demand Capacity Resource other than an Active Demand Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(iv), the ISO shall use the Section III.15.7.1.5.4 audit results. The annual and Monthly Qualified Capacity of such resources shall be determined pursuant to Sections III.15.3.4.2 and III.15.3.4.3, respectively.

To determine the Seasonal Qualified Capacity Values of a Distributed Energy Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(v), the ISO shall use the audit results specified therein for the corresponding asset type. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to III.15.3.5.2 and III.15.3.5.3, respectively.

To determine the Seasonal Qualified Capacity Values of an Import Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant Section III.15.2.6(c)(vi), the ISO shall use the performance data results specified therein. The annual and monthly Qualified Capacity of such a resource shall be determined pursuant to III.15.3.3.

To determine the Seasonal Qualified Capacity Values of a resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and that has elected to demonstrate commercial capacity pursuant Section III.15.2.6(d), the ISO shall use the values developed pursuant to Section III.15.2.6(d). The annual Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3, Section III.15.3.4.2, or Section III.15.3.5.2, as applicable to

the relevant resource type. The Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.4, III.15.3.4.3, or Section III.15.3.5.3, as applicable to the relevant resource type.

**III.15.3.2 Qualified Capacity for Generating Capacity Resources.**

The summer, winter, annual, and monthly Qualified Capacity for Generating Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.2.

**III.15.3.2.1. Summer Qualified Capacity.**

(a) For the purpose of Annual Capacity Auction qualification, the summer Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the Capacity Demonstration Deadline each year, with only positive summer ratings included in the median calculation. Where a Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Generating Capacity Resource shall be equal to the median of all the Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the Capacity Demonstration Deadline of each year, with only positive summer ratings included in the median calculation.

(b) For the purpose of Annual Capacity Auction qualification, the summer Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the average of the median of the Intermittent Power Resource's net output during Summer Intermittent Reliability Hours for each of the previous five summer periods. If there are fewer than five full summer periods since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation, the summer Qualified Capacity of such resource shall be the average of the median of the Intermittent Power Resource's net output during Summer Intermittent Reliability Hours in each of the previous summer periods, or portion thereof, since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation. The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which there was a system-wide Capacity Scarcity Condition, and for Intermittent Power Resources in an import-constrained Capacity Zone, all summer period hours in which there was a Capacity Scarcity Conditions in that Capacity Zone.

**III.15.3.2.2. Winter Qualified Capacity.**

(a) For the purpose of Annual Capacity Auction qualification, the winter Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the Capacity Demonstration Deadline of each year, with only positive winter ratings included in the median calculation. Where a Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Generating Capacity Resource shall be equal to the median of all the Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the Capacity Demonstration Deadline of each year, with only positive winter ratings included in the median calculation.

(b) For the purpose of Annual Capacity Auction qualification, the winter Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the average of the median of the Intermittent Power Resource's net output during Winter Intermittent Reliability Hours for each of the previous five summer periods. If there are fewer than five full summer periods since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation, the winter Qualified Capacity of such resource shall be the average of the median of the Intermittent Power Resource's net output during Winter Intermittent Reliability Hours in each of the previous winter periods, or portion thereof, since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation. The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which there was a system-wide Capacity Scarcity Condition, and for Intermittent Power Resources in an import-constrained Capacity Zone, all winter period hours in which there was a Capacity Scarcity Conditions in that Capacity Zone.

**III.15.3.2.3. Annual Qualified Capacity.**

The Annual Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The Annual Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

**III.15.3.2.4. Monthly Qualified Capacity.**

The Monthly Qualified Capacity of a Generating Capacity Resource shall be the resource's most recent Seasonal Claimed Capability value for the season applicable to the relevant month; for those Generating Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

**III.15.3.3. Qualified Capacity for Import Capacity Resources.**

The summer, winter, annual, and monthly Qualified Capacity of an Import Capacity Resource backed by an External Control Area shall be based on the values and data submitted during the qualification process, subject to ISO review and verification. The summer, winter, annual, and monthly Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be based on the data submitted during the qualification process, subject to ISO review and verification, and calculated based on the summer and winter Qualified Capacity of the resources underlying the Import Capacity Resource, in accordance with Sections III.15.3.2.1 and III.15.3.2.2.

**III.15.3.4. Qualified Capacity for Demand Capacity Resources.**

The summer, winter, annual, and monthly Qualified Capacity for Demand Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.4.

**III.15.3.4.1. Summer and Winter Qualified Capacity.**

(a) For Demand Capacity Resources composed of Energy Efficiency measures, the summer (or winter, as applicable) Qualified Capacity shall equal the sum of the summer (or winter, as applicable) demand reduction values of the installed Energy Efficiency measures as of the Capacity Demonstration Deadline (excluding any capacity that will retire or deactivate, or whose Measure Life will expire, prior to the start of the applicable season of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses).

(b) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the summer and winter Qualified Capacity shall equal the median of the resource's Seasonal DR Audit value or Passive DR Audit value from the five most recent years, for the relevant season, increased by average avoided peak transmission and distribution losses. Where a Demand Capacity Resource has fewer than five summer or winter Seasonal Audit Values, as applicable, then the summer (or winter) Qualified Capacity for that Demand Capacity Resource shall be equal to the median of all the resource's previous

summer (or winter) Seasonal Audit Values, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation.

**III.15.3.4.2. Annual Qualified Capacity.**

The Annual Qualified Capacity of a Demand Capacity Resource shall equal the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

**III.15.3.4.3 Monthly Qualified Capacity.**

The Monthly Qualified Capacity of a Demand Capacity Resource, other than a resource composed of Energy Efficiency measures, shall equal its most recent Seasonal DR Audit value or Passive DR Audit value for the season applicable to the relevant month; for those Demand Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

The Monthly Qualified Capacity of a Demand Capacity Resource composed of Energy Efficiency measures shall equal the most recently-determined summer or winter demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire, deactivate, or whose Measure Life will expire, prior to the start of the relevant Obligation Month, and increased by average avoided peak transmission and distribution losses).

**III.15.3.5. Qualified Capacity of Distributed Energy Capacity Resources.**

The summer, winter, annual, and monthly Qualified Capacity for Distributed Energy Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.5.

**III.15.3.5.1. Summer and Winter Qualified Capacity.**

The summer (or winter, as applicable) Qualified Capacity of a Distributed Energy Capacity Resource that is not an Intermittent Power Resource shall equal the median of the resource's summer (or winter) Seasonal Audit Value from the five most recent years, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation. Where a Distributed Energy Capacity Resource has fewer than five summer (or winter) Seasonal Audit Values, then the summer (or winter) Qualified Capacity for that Distributed Energy Capacity Resource shall be

equal to the median of the resource's previous summer (or winter) Seasonal Audit Values, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation.

The summer or winter Qualified Capacity of Distributed Energy Capacity Resources that are Intermittent Power Resources shall be determined in accordance with the rules for Generating Capacity Resources that are Intermittent Power Resources in Section III.15.3.2.

**III.15.3.5.2. Annual Qualified Capacity.**

Annual Qualified Capacity for a Distributed Energy Capacity Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, unless the Distributed Energy Capacity Resource is an Intermittent Power Resource, in which case the Annual Qualified Capacity shall be equal to the resource's summer Qualified Capacity.

**III.15.3.5.3. Monthly Qualified Capacity.**

The Monthly Qualified Capacity of a Distributed Energy Capacity Resource shall equal the most recent Seasonal DECR Audit for the season applicable to the relevant month; for those Distributed Energy Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

**III.15.3.6. Adjustment for Significant Decreases in Capacity.**

For a Generating Capacity Resource, Import Capacity Resource backed by an External Resource, Distributed Energy Capacity Resource, or Demand Capacity Resource, if the most recent summer Seasonal Claimed Capability rating, summer season Import Capacity Resource performance data submitted pursuant to Section III.15.2.1.1.1, summer Seasonal DECR Audit Value, summer Seasonal DR Audit Value, or summer Passive DR Audit Value as of the Annual Capacity Auction's Capacity Demonstration Deadline is below the resource's Qualified Capacity by more than the threshold defined in the following formula:

$$Threshold = min[max(10\% \times QC_{Summer}, 2\ MW), 10\ MW]$$

Where,

$QC_{Summer}$ = the resource's summer Qualified Capacity

then the Lead Market Participant must elect one of the two treatments set forth in this Section III.15.3.6 by the close of the Seasonal Qualified Capacity Challenge and Restoration Plan Submission Window. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.15.3.6(b) and fails to meet the associated requirements, then the treatment described in Section III.15.3.6(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Annual Capacity Auction only, to have the resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability rating, summer Seasonal DECR Audit Value, Seasonal DR Audit Value, or Passive DR Audit Value as of the Capacity Demonstration Deadline, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) A Lead Market Participant may elect: (i) to submit a restoration plan describing the measures that will be taken and showing that the Generating Capacity Resource, Import Capacity Resource backed by an External Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section III.15.3.2, Section III.15.3.3, Section III.15.3.4, or Section III.15.3.5 by the start of the relevant Capacity Commitment Period; and (ii) to have the Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.15.3.2, Section III.15.3.3, Section III.15.3.4, or Section III.15.3.5 for the Annual Capacity Auction. The ISO shall review submitted restoration plans in accordance with the requirements and timelines set forth in Section III.15.2.7.

### III.15.3.7. Resources Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where a Generating Capacity Resource (other than an Intermittent Power Resource), Demand Capacity Resource, or Import Capacity Resource has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.15.3, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, in accordance with Section III.15.2.8; or (ii) have its Annual Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

Where a Distributed Energy Capacity Resource (other than an Intermittent Power Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this

Section III.15.3, then that resource must have its Annual Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

**III.15.4. Annual Capacity Auction.**

**III.15.4.1 Capacity Offers.**

Lead Market Participants submitting Capacity Offers in the Annual Capacity Auction shall submit Capacity Offers for the Capacity Commitment Period associated with the Annual Capacity Auction as specified in this Section III.15.4.1.

(a) Each Capacity Offer shall be associated with a Capacity Resource for which an Annual Qualified Capacity value has been established for the Annual Capacity Auction through the Annual Capacity Auction qualification process set forth in Sections III.15.2 and III.15.3.

(b) Capacity Offers must be submitted during the Annual Capacity Auction Offer Window, the dates of which will be specified as published in the Capacity Auction Calendar. Capacity Offers are not considered final until the close of the Annual Capacity Auction Offer Window and may be amended or corrected as necessary until such time as the window closes.

(c) If a Lead Market Participant fails to submit a Capacity Offer for a resource subject to the requirements of Section III.A.22.1, the ISO shall enter a Capacity Offer for the resource into the Annual Capacity Auction in accordance with Section III.A.22.1(d).

(d) Each Capacity Offer must specify at least one price-quantity pair, which consists of one price, denominated in $/kW-month to an accuracy of at most three digits to the right of the decimal point, and a quantity value, expressed in MW to an accuracy of up to three decimal places. The Capacity Offer may specify up to ten price-quantity pairs, where each such pair represents the total amount of capacity offered from the Capacity Resource at the price specified. If more than one price-quantity pair is submitted, the price-quantity pairs must specify prices and quantity values in such a way that, when the price-quantity pairs are ordered from lowest price to highest price, the quantity value in each price-quantity pair increases with each successive, higher-priced price-quantity pair. The price-quantity pair with the greatest specified price must include the Capacity Resource's total Annual Qualified Capacity. The Capacity Offer must not contain any offer prices less than $0.00/kW-month or greater than the Capacity Auction Offer Price Cap, unless otherwise allowed pursuant to Section III.A.22.2.3 and subsection (e) of this Section III.15.4.1 or required by Section III.A.21 and subsection (f) of this Section III.15.4.1. The Capacity Offer must not specify a total MW quantity value that exceeds the Capacity Resource's Annual Qualified Capacity.

(e) A price-quantity pair in a Capacity Offer must not specify a price above the Capacity Offer Price Threshold, except under the following circumstances:

(i) the Lead Market Participant for the Capacity Resource submitted the price-quantity pair to the Internal Market Monitor as part of a Proposed Capacity Offer, pursuant to Section III.A.22.2.2;

(ii) the Internal Market Monitor determined an Allowable Capacity Offer Price relative to the price-quantity pair pursuant to Section III.A.22.2.3; and

(iii) the specified price in the Capacity Offer does not exceed the price specified in the price-quantity pair reviewed by the Internal Market Monitor.

(f) For capacity included in a Capacity Offer that is subject to a Capacity Offer Floor Price pursuant to Section III.A.21.3, the price specified must not be less than the Capacity Offer Floor Price.

(g) A Capacity Offer may specify a Rationing Minimum Limit up to which the offer may not be rationed and must be accepted or rejected in whole. Without such indication, offers shall be rationable up to the total MW quantity in the offer that is priced at or below the Capacity Offer Price Threshold, subject to the auction clearing constraint described in Section III.15.4.2.2(d). The lowest priced price-quantity pair in a Capacity Offer that specifies a Rationing Minimum Limit must specify a quantity value equal to or greater than the specified Rationing Minimum Limit. Notwithstanding the foregoing, a Capacity Offer for an Import Capacity Resource may only specify a Rationing Minimum Limit pursuant to this subsection (g) if the Import Capacity Resource is associated with an Elective Transmission Upgrade, as described in Section III.15.2.1.1.1.

(h) If the Capacity Offer specifies any price above the Capacity Offer Price Threshold, the Capacity Offer may elect to have the Above-Threshold Offer Segment be treated as rationable, subject to any Rationing Minimum Limit specified pursuant to subsection (g). Without such an election, the Above-Threshold Offer Segment will be treated as non-rationable and accepted or rejected in whole. Notwithstanding the foregoing, a Capacity Offer for an Import Capacity Resource may only elect rationability for the Above-Threshold Offer Segment pursuant to this subsection (h) if the Import

Capacity Resource is associated with an Elective Transmission Upgrade, as described in Section III.15.2.1.1.1.

(i) In order to give effect to a self-supply designation made by a load serving entity pursuant to Section III.15.2.9 for any portion of the Capacity Resource's Annual Qualified Capacity, the Capacity Offer for such resource must (i) identify the load serving entity for which its capacity will serve as self-supplied capacity and the MW quantity of self-supplied capacity and (ii) include a price-quantity pair with an offer price of $0.00/kW-month that includes the amount of such capacity, unless such capacity is subject to a Capacity Offer Floor Price. If the self-supplied capacity is subject to a Capacity Offer Floor Price, then the price specified in the price-quantity pair including the self-supplied capacity must equal the Capacity Offer Floor Price.

(j) A Capacity Offer for a Generating Capacity Resource with a contract to export capacity during the Capacity Commitment Period must specify an Export Offer Segment and the interface over which the Export Offer Segment will be exported.

(k) A Lead Market Participant for a Capacity Resource that is subject to delayed deactivation pursuant to Sections II.52 and II.53 shall not enter a Capacity Offer for any capacity supplied by the Capacity Resource that is subject to delayed deactivation. The ISO shall enter such Capacity Resource's capacity subject to delayed deactivation into the Annual Capacity Auction at a price of $0.00/kW-month.

(l) If a prior multi-year Capacity Supply Obligation and Capacity Clearing Price election for the Capacity Resource had been made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 for a Forward Capacity Auction, the Capacity Offer submitted for such Capacity Resource must include a price-quantity pair with an offer price of $0.00/kW-month that includes the total amount of the resource's capacity that cleared subject to such election.

**III.15.4.2. Conduct of the Annual Capacity Auction**.

The ISO shall determine Capacity Supply Obligations and Capacity Clearing Prices for the Capacity Commitment Period by conducting the Annual Capacity Auction as described in this Section III.15.4.2.

**III.15.4.2.1. Replacement of Specified Prices for Mitigation Purposes.**

After the Annual Capacity Auction Offer Window, the ISO shall replace specified prices in submitted Capacity Offers as necessary, pursuant to Section III.A.22.2.4(c). Any such adjusted Capacity Offers shall be inputs for the Annual Capacity Auction.

**III.15.4.2.2. Clearing of the Annual Capacity Auction.**

(a) In determining Capacity Supply Obligations and Capacity Clearing Prices, the ISO shall employ an optimization algorithm that is designed to maximize social surplus in order to clear Capacity Offers, capacity entered into the auction by the ISO as described in Section III.15.4.1(k), and any Proxy Capacity Offers against the capacity demand curves calculated in accordance with Section III.15.1.1. In clearing Capacity Offers, the optimization algorithm shall take into account, as applicable, the inputs and constraints set forth in this Section III.15.4.2.2.

(b) The optimization algorithm shall take into account the following: (i) all price-quantity pairs in Capacity Offers for the Annual Capacity Auction submitted pursuant to Section III.15.4.1, subject to any adjustments made pursuant to Section III.15.4.2.1 and the constraint described in subsection (c) of this Section III.15.4.2.1; (ii) any Rationing Minimum Limits and rationability elections specified in Capacity Offers pursuant to Section III.15.4.1(g) and Section III.15.4.1(h), respectively; (iii) capacity from a Capacity Resource subject to delayed deactivation pursuant to Sections II.52 and II.53 at a default price of $0.00/kW-month; (iv) the set of distinct Capacity Zones determined to be modeled in the Annual Capacity Auction pursuant to Section III.12.4; (v) the System-Wide Capacity Demand Curve calculated in accordance with Section 15.1.1.1; (vi) any Capacity Zone Demand Curves for import-constrained and export-constrained Capacity Zones, calculated in accordance with Sections 15.1.1.2 and 15.1.1.3, respectively; (vii) external interface limits calculated pursuant to Section III.12.10; and (viii) any Proxy Capacity Offers for the Annual Capacity Auction as determined pursuant to Section III.A.24.7, which shall be treated as non-rationable.

(c) The optimization algorithm shall not take into account price-quantity pairs in Capacity Offers that specify a price that exceeds the Capacity Auction Offer Price Cap.

(d) Capacity entered into the Annual Capacity Auction at a price of $0.00/kW-month shall clear the auction.

(e) A Capacity Offer that specifies a Rationing Minimum Limit pursuant to Section III.15.4.1(g) shall not clear at quantities less than the specified Rationing Minimum Limit, and Above-Threshold Offer

Segments that are non-rationable pursuant to Section III.15.4.1(h) shall not clear at quantities less than the MW quantity of the segment.

(f) For an Export Offer Segment specified in a Capacity Offer that indicates a Generating Capacity Resource's contract to export capacity over an external interface connected to an import-constrained Capacity Zone from another Capacity Zone, or over an external interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone, the ISO shall model the Export Offer Segment as though that quantity of capacity were located in the Capacity Zone where the external interface identified in the Capacity Offer is located and adjust Capacity Zone Demand Curves as necessary to reflect such modeling.

(g) In determining the clearing result that accounts for auction inputs and satisfies all applicable constraints, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including clearing results where a Capacity Offer with a specified price below the Capacity Clearing Price does not clear.

(h) Where the clearing of the Annual Capacity Auction either system-wide or in a single Capacity Zone results in a tie (that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs), the following rules shall apply in sequence, as necessary, to determine clearing: (i) if multiple Capacity Offers may be rationed, they will be rationed proportionately; and (ii) the Capacity Offer associated with the Lead Market Participant having the lower market share in the capacity auction shall be cleared.

(i) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be the price specified by the System-Wide Capacity Demand Curve for the system-wide capacity entered into the Annual Capacity Auction that maximizes social surplus. In no case, however, shall the Capacity Clearing Price for the Rest-of-Pool Capacity Zone be less than the highest price specified in an offer for capacity that clears the auction, excluding any capacity that, due to its specified price, would not have cleared but for the fact that it is located within an import-constrained Capacity Zone that has a cleared quantity of capacity equal to or less than the truncation point for the zone's Capacity Zone Demand Curve.

(j) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an import-constrained Capacity Zone shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the import-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the import-constrained Capacity Zone and that clears the auction.

(k) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the export-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Rest-of-Pool Zone; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

(l) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an export-constrained Capacity Zone that is a nested export-constrained Capacity Zone, shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the export-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

(m) The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for an import-constrained Capacity Zone shall not exceed the Capacity Auction Offer Price Cap. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

(n) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an interface between the New England Control Area and an external Control Area shall be equal to:

(i) if the quantity of capacity over the external interface that clears the auction is equal to the external interface limit for such interface, the highest price specified in a Capacity Offer for capacity that is supplied from a resource offering capacity over such external interface and that clears the auction; or

(ii) if the quantity of capacity over the external interface that clears the auction is less than the external interface limit for such interface, the Capacity Clearing Price for the Capacity Zone associated with the external interface.

**III.15.4.2.3. Results of the Annual Capacity Auction.**

(a) Annual Capacity Supply Obligations shall be awarded to Capacity Resources in accordance with the results of the Annual Capacity Auction clearing mechanics described in Section III.15.4.2.2. For Intermittent Power Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.15.2) shall be adjusted based on the winter Qualified Capacity as determined pursuant to Section III.15.3.2.2. Additional Capacity Supply Obligations may be awarded in accordance with Section III.15.4.2.4.

(b) The Capacity Clearing Prices in each Capacity Zone modeled in the Annual Capacity Auction shall be the clearing prices determined as a result of the Annual Capacity Auction clearing mechanics described in Section III.15.4.2.2.

**III.15.4.2.4. Additional Clearing of Auction in the Event of Cleared Proxy Offers.**

If any Proxy Capacity Offer entered into the Annual Capacity Auction clears and receives a Capacity Supply Obligation, the ISO shall conduct an additional run of the auction. This additional run shall use the same methodology described in Section III.15.4.2.2, except that the additional run shall (i) exclude all Proxy Capacity Offers and (ii) enter all other capacity that cleared in the primary run of the Annual Capacity Auction at a price of $0.00/kW-month. The additional run of the auction shall not affect the Capacity Clearing Prices of the primary run of the Annual Capacity Auction pursuant to Section III.15.4.2.2. Capacity (other than capacity still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receives a Capacity Supply Obligation as a result of the primary run of the Annual Capacity Auction shall be paid the Capacity

Clearing Price in the Capacity Zone associated with the capacity during the associated Capacity Commitment Period. Where the additional run of the auction procures additional capacity, that additionally procured capacity shall be paid the price resulting from the additional run in the Capacity Zone associated with that additional capacity during the associated Capacity Commitment Period, and such price shall be equal to or greater than the price resulting from the primary run of the Annual Capacity Auction in that Capacity Zone.

**III.15.4.3. Publication of Annual Capacity Auction Results.**

As soon as practicable after the Annual Capacity Auction is complete, the ISO shall publish the results of that Annual Capacity Auction publicly on its website, including the set of Capacity Zones modeled in the auction, the Capacity Clearing Prices in each of those Capacity Zones, and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. The published information shall identify Proxy Capacity Offers that cleared, if any, in the primary run of the Annual Capacity Auction.

**III.15.5. Monthly Reconfiguration Auctions.**

For each Capacity Commitment Period, the ISO shall conduct Monthly Reconfiguration Auctions as described in this Section III.15.5. Monthly Reconfiguration Auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in the Monthly Reconfiguration Auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Section III.15.5.1) to clear supply offers (i.e., offers to assume a Capacity Supply Obligation) and demand bids (i.e., bids to shed a Capacity Supply Obligation) for each Capacity Zone included in the reconfiguration auction. Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected. Resources that are able to meet the requirements in other Capacity Zones shall be allowed to clear to meet such requirements, subject to the constraints modeled in the auction.

**III.15.5.1. Capacity Zones Included in Monthly Reconfiguration Auctions.**

Each Monthly Reconfiguration Auction associated with a Capacity Commitment Period shall include each of, and only, the Capacity Zones and external interfaces modeled in the Annual Capacity Auction for that Capacity Commitment Period in accordance with Section III.15.4.2.2.

**III.15.5.2. Participation in Monthly Reconfiguration Auctions.**

Each supply offer and demand bid in a Monthly Reconfiguration Auction must be associated with a specific resource and must satisfy the requirements of this Section III.15.5.2. All resource types may submit supply offers and demand bids in reconfiguration auctions. In accordance with Section III.A.13.2, supply offers and demand bids submitted for Monthly Reconfiguration Auctions shall not be subject to mitigation by the Internal Market Monitor. Offers composed of separate resources may not participate in reconfiguration auctions. Resources with capacity subject to delayed deactivation pursuant to Sections II.52 and II.53 may not participate in reconfiguration auctions, unless otherwise authorized pursuant to the terms of a cost-of-service agreement of the type described in Section II.54.1. Participation in any reconfiguration auction is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of the offer and bid deadline. The offer and bid deadline for each Monthly Reconfiguration Auction shall be announced by the ISO no later than 10 Business Days prior to that deadline. Upon issuance of the monthly bilateral results for the associated Obligation Month, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that monthly auction, as calculated pursuant to this Section III.15.5.2.

**III.15.5.2.1. Supply Offers in Monthly Reconfiguration Auctions.**

(a) All supply offers in Monthly Reconfiguration Auctions shall be submitted by the Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, denominated in $/kW-month.

(b) A resource may not submit a supply offer for a Monthly Reconfiguration Auction unless a Monthly Qualified Capacity value has been established for the resource for the month associated with the Monthly Reconfiguration Auction pursuant to the qualification processes described in Sections III.15.2 and III.15.3.

(c) The amount of capacity up to which a resource may submit a supply offer in a Monthly Reconfiguration Auction shall be the difference (but in no case less than zero) between (i) the resource's Monthly Qualified Capacity for the month associated with the auction, as determined pursuant to Section III.15.3 during the most recent qualification process for the resource; and (ii) the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month.

**III.15.5.2.2. Demand Bids in Monthly Reconfiguration Auctions.**

(a) All demand bids in Monthly Reconfiguration Auctions shall be submitted by the Lead Market Participant and shall specify the amount of capacity bid in MW and the price, denominated in $/kW-month.

(b) To submit a demand bid in a Monthly Reconfiguration Auction, a resource must have a Capacity Supply Obligation for the month associated with that Monthly Reconfiguration Auction.

(c) Where capacity associated with a Self-Supplied Capacity Resource that cleared in the Annual Capacity Auction for the Capacity Commitment Period is offered in a Monthly Reconfiguration Auction, a resource acquiring a Capacity Supply Obligation in that Monthly Reconfiguration Auction shall not as a result become a Self-Supplied Capacity Resource.

(d) Each demand bid submitted to the ISO for a Monthly Reconfiguration Auction shall be no greater than the amount of the resource's capacity that is already obligated for the month associated with that Monthly Reconfiguration Auction as of the offer and bid deadline for the auction.

**III.15.5.3. Clearing Offers and Bids in Monthly Reconfiguration Auctions.**

All supply offers and demand bids are rationable and may be cleared in whole or in part in Monthly Reconfiguration Auctions.

**III.15.5.4. Conduct of Monthly Reconfiguration Auctions.**

Prior to each month in the Capacity Commitment Period, the ISO shall conduct a Monthly Reconfiguration Auction for whole-month capacity commitments during that month. For each Monthly Reconfiguration Auction, the ISO shall employ an optimization algorithm that is designed to maximize social surplus in order to clear the supply offers against demand bids submitted for the auction. The truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Section III.15.1.1.2 and Section III.15.1.1.3 and external interface limits established pursuant to Section III.12 shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in Monthly Reconfiguration Auctions.

**III.15.5.5. Adjustment to Capacity Supply Obligations**.

For each supply offer that clears in a Monthly Reconfiguration Auction, the resource's Capacity Supply Obligation for the month associated with the auction shall be increased by the amount of capacity that clears. For each demand bid that clears in a Monthly Reconfiguration Auction, the resource's Capacity Supply Obligation for the month associated with the auction shall be decreased by the amount of capacity that clears.

**III.15.6. Bilateral Capacity Contracts.**

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals and Capacity Load Obligation Bilaterals in accordance with this Section III.15.6, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation. To the extent necessary for the ISO's review and approval of any of the bilateral contracts described in this Section III.15.6, the ISO shall apply the Capacity Zones and external interfaces modeled as inputs and constraints in the Annual Capacity Auction for the applicable Capacity Commitment Period, as described in Section III.15.4.2.2. Resources with capacity subject to delayed deactivation pursuant to Sections II.52 and II.53 may not participate in Capacity Supply Obligation Bilaterals, unless otherwise authorized pursuant to the terms of a cost-of-service agreement of the type described in Section II.54.1.

**III.15.6.1. Capacity Supply Obligation Bilaterals.**

A Capacity Transferring Resource having a Capacity Supply Obligation and seeking to shed that obligation may enter into a Capacity Supply Obligation Bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part, to a Capacity Acquiring Resource, or portion thereof, for a whole-month period during the Capacity Commitment Period, as described in this Section III.15.6.1.

**III.15.6.1.1. Terms of and Participation in Capacity Supply Obligation Bilaterals.**

(a) Capacity Supply Obligation Bilaterals are available for monthly periods, and a Capacity Supply Obligation Bilateral must be coterminous with a calendar month.

(b) The qualification of Capacity Acquiring Resources for participation in Capacity Supply Obligation Bilaterals is determined in the same manner as the qualification of resources submitting supply offers for Monthly Reconfiguration Auctions as specified in Section III.15.5.2.1(b). A resource that does not have a Monthly Qualified Capacity value established for the month covered by the Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that month.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the monthly Capacity Supply Obligation of the Capacity Transferring Resource. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the amount of unobligated Monthly Qualified Capacity of the Capacity Acquiring Resource for the month covered by the Capacity Supply Obligation Bilateral. For the purpose of this subsection (c), unobligated Monthly Qualified Capacity refers to the Monthly Qualified Capacity that was

determined pursuant to Section III.15.3 in the most recent qualification process for the resource prior to the submission of the Capacity Supply Obligation Bilateral to the ISO and that is not subject to a Capacity Supply Obligation.

(d) A resource, or a portion thereof, that has been designated as a Self-Supplied Capacity Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied Capacity Resource as a result of the transaction.

(e) Capacity Supply Obligation Bilaterals are allowed between a Capacity Transferring Resource and a Capacity Acquiring Resource that are located within different Capacity Zones and across external interfaces modeled as part of the Annual Capacity Auction for the Capacity Commitment Period of the relevant monthly period, subject to the transmission interface limits between Capacity Zones and external interface limits, as described in Section III.15.6.1.4(b).

(f) Participation in any Capacity Supply Obligation Bilateral is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of submission to the ISO.

**III.15.6.1.2. Timing of Submission and Prior Notification to the ISO.**

The Lead Market Participant for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Capacity Supply Obligation Bilaterals in the Capacity Auction Calendar. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

**III.15.6.1.3. Contents of Submission to the ISO.**

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, denominated in $/kW-

month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

**III.15.6.1.4. ISO Review.**

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral and shall reject the Capacity Supply Obligation Bilateral if any of the submission and participation requirements described in this Section III.15.6.1 are not met. For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.

(b) After the close of the submittal window, the ISO shall conduct a review to determine the deliverability of the submitted Capacity Supply Obligation Bilaterals. In its review, the ISO shall model as constraints the truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Sections III.15.1.1.2 and III.15.1.1.3 and external interface limits established pursuant to Section III.12 for the applicable Capacity Commitment Period. The ISO shall reject Capacity Supply Obligation Bilaterals that are not fully deliverable up to their specific MW values without violating transmission transfer limits between Capacity Zones or external transfer limits. Transactions will only be accepted or rejected in their entirety. The ISO shall approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected, the Lead Market Participant for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the basis for such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

**III.15.6.1.5. Approval.**

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource for the month covered by the Capacity Supply Obligation Bilateral shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply

Obligation of the Capacity Acquiring Resource for the month covered by the Capacity Supply Obligation Bilateral shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

**III.15.6.2. Capacity Load Obligations Bilaterals.**

A Capacity Load Obligation Transferring Participant seeking to shed its Capacity Load Obligation may enter into a Capacity Load Obligation Bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone to a Capacity Load Obligation Acquiring Participant seeking to acquire a Capacity Load Obligation, as described in this Section III.15.6.2.

**III.15.6.2.1. Terms of and Participation in Capacity Load Obligation Bilaterals.**

A Capacity Load Obligation Bilateral must be in whole calendar month increments, may not exceed one year in duration, and must begin and end within the same Capacity Commitment Period. A Capacity Load Obligation Transferring Participant will be permitted to transfer, and a Capacity Load Obligation Acquiring Participant will be permitted to acquire, a Capacity Load Obligation if after entering into a Capacity Load Obligation Bilateral and submitting related information to the ISO within the specified submittal time period, the ISO approves such Capacity Load Obligation Bilateral.

**III.15.6.2.2. Timing of Submission to the ISO.**

Either the Capacity Load Obligation Transferring Participant or the Capacity Load Obligation Acquiring Participant may submit a Capacity Load Obligation Bilateral to the ISO. All Capacity Load Obligation Bilaterals must be submitted to the ISO in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial daily settlements of payments and charges associated with the Annual Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 p.m. on the first Business Day of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

**III.15.6.2.3. Contents of Submission to the ISO.**

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following: (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant

and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

**III.15.6.2.4. ISO Review.**

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section III.15.6.2 are not met.

**III.15.6.2.5. Approval.**

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral.

**III.15.7. Obligations of Capacity Suppliers.**

Resources assuming a Capacity Supply Obligation through an Annual Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a Monthly Reconfiguration Auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.15.7 for each Capacity Commitment Period.

**III.15.7.1. Resources with Capacity Supply Obligations.**

A resource with a Capacity Supply Obligation assumed through an Annual Capacity Auction, Monthly Reconfiguration Auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.15.7.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

**III.15.7.1.1. Generating Capacity Resources with Capacity Supply Obligations.**

**III.15.7.1.1.1. Energy Market Offer Requirements**.

(a) A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically

available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

(i) the sum of the Generating Capacity Resource's Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours; or

(ii) if the Generating Capacity Resource cannot meet the offer requirements in Section III.15.7.1.1.1(a)(i) due to physical design limits, then the resource shall be offered into the Day-Ahead Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.

(b) Notwithstanding the foregoing, if the Generating Capacity Resource is a Settlement Only Resource, it may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

**III.15.7.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.**

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the known capability of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.19.

**III.15.7.1.1.3. [Reserved.]**

**III.15.7.1.1.4. [Reserved.]**

**III.15.7.1.1.5. Additional Requirements for Generating Capacity Resources.**

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1 and the requirement to provide to the ISO, upon request and as soon as practicable, confirmation of gas volume schedules sufficient to deliver the energy scheduled for each Generating Capacity Resource using natural gas; and

(c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures (except that Settlement Only Resources are not subject to outage requirements), provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

**III.15.7.1.2. Import Capacity Resources with Capacity Supply Obligations.**

**III.15.7.1.2.1. Energy Market Offer Requirements.**

A Market Participant with an Import Capacity Resource must offer one or more External Transactions to import energy in the Day-Ahead Energy Market and Real-Time Energy Market for every hour of each Operating Day at the same external interface that, in total, equal the resource's Capacity Supply Obligation, except that:

(a) the offer requirement does not apply to any hour in which any External Resource associated with an Import Capacity Resource is on an outage;
(b) the Day-Ahead Energy Market offer requirement does not apply to any hour in which the import transfer capability of the external interface is 0 MW, and;
(c) the Real-Time Energy Market offer requirement does not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which Coordinated Transaction Scheduling is implemented.

Each External Transaction submitted in the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

Each External Transaction submitted in the Real-Time Energy Market in accordance with Section III.1.10.7 must reference the associated Import Capacity Resource.

**III.15.7.1.2.2. Additional Requirements for Import Capacity Resources.**

A Market Participant with an Import Capacity Resource that is associated with an External Resource must:

(a) comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the External Resource's native Control Area, and;
(b) notify the ISO of all outages impacting the Capacity Supply Obligation of the Import Capacity Resource in accordance with the outage notification requirements in ISO New England Operating Procedure No. 5.

**III.15.7.1.3. Intermittent Power Resources with Capacity Supply Obligations.**

**III.15.7.1.3.1. Energy Market Offer Requirements**.

(a) Market Participants with Intermittent Power Resources that are Dispatchable Resources and have a Capacity Supply Obligation are required to submit offers in the Day-Ahead Energy Market consistent with the Market Participant's expectation of the output of the resource in Real-Time. Market Participants with non-dispatchable Intermittent Power Resources with a Capacity Supply Obligation may submit, but are not required to submit, offers into the Day-Ahead Energy Market. Market Participants are required to submit offers for Intermittent Power Resources with a Capacity Supply Obligation for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day-Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

(b) Notwithstanding the foregoing, an Intermittent Power Resource that is a Settlement Only Resource may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

**III.15.7.1.3.2. [Reserved.]**

**III.15.7.1.3.3. Additional Requirements for Intermittent Power Resources**.

Intermittent Power Resources with Capacity Supply Obligations are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals (except that Intermittent Power Resources that are Settlement Only Resources need not comply with outage requirements).

**III.15.7.1.4. [Reserved.]**

**III.15.7.1.5. Demand Capacity Resources with Capacity Supply Obligations.**

**III.15.7.1.5.1. Energy Market Offer Requirements.**

(a) A Market Participant with an Active Demand Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers for its Demand Response Resources into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.15.7.1.5.1; for purposes of the following comparisons, the portion of Demand Reduction Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. The sum of the Demand Reduction Offers must be equal to or greater than the Active Demand Capacity Resource's Capacity Supply Obligation whenever the Demand Response Resources are physically available. If the Demand Response Resources are physically available at a level less than the Active Demand Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers will equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet the following requirement:

(i) the sum of the Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time plus Minimum Reduction Time plus Minimum Time Between Reductions is less than or equal to 72 hours.

(b) Seasonal Peak Demand Capacity Resources and On-Peak Demand Capacity Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

**III.15.7.1.5.2. Requirement that Offers Reflect Accurate Demand Response Resource Operating Characteristics.**

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a Demand Response Resource associated with an Active Demand Capacity Resource must reflect the then-known operating characteristics of the resource. Consistent with Section III.1.10.9(d), Demand Response Resources must re-declare to the ISO any changes to offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.19.

**III.15.7.1.5.3. Additional Requirements for Demand Capacity Resources.**

(a) A Market Participant may not associate an Asset with a non-commercial Demand Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Demand Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) An Energy Efficiency measure may be added to an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource (other than one consisting of Load Management or Distributed Generation) until two years after the start of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation; provided, however, that a resource that qualified for a Forward Capacity Auction associated with a Capacity Commitment Period beginning on or before June 1, 2024 may install Energy Efficiency measures until May 31, 2027. Once an Energy Efficiency measure has been associated with an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, the measure may not be transferred to a different resource.

(c) For purposes of confirming Capacity Market Commercial Operation as described in Section III.15.2.6, the ISO shall use a summer Seasonal DR Audit value or summer Passive DR Audit value to verify the capacity rating of a Demand Capacity Resource with summer Qualified Capacity. A winter Seasonal DR Audit value or winter Passive DR Audit value may only be used to verify the winter commercial capacity of a Demand Capacity Resource. The summer and winter commercial capacity of a Demand Capacity Resource consisting of Energy Efficiency measures may be verified in any month of the year.

(d) For Active Demand Capacity Resources, a summer Seasonal DR Audit value shall be established for use from April 1 through November 30 and a winter Seasonal DR Audit value shall be established for use from December 1 through March 31. The summer or winter Seasonal DR Audit value of an Active Demand Capacity Resource is equal to the sum of the like-season Seasonal DR Audit values of its constituent Demand Response Resources as determined pursuant to Section III.1.5.1.3.1. The Seasonal DR Audit value of an Active Demand Capacity Resource shall automatically update whenever a new Seasonal DR Audit value is approved for a constituent Demand Response Resource or with changes to the makeup of the constituent Demand Response Resources.

(e) On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources shall in addition: (i) comply with the ISO's measurement and verification requirements pursuant to Section III.15.2.1.1.2.1. and the ISO New England Manuals; and (ii) comply with the auditing and rating requirements as detailed in Sections III.15.7.1.5.4 and III.15.7.1.5.5 and the ISO New England Manuals.

(f) Active Demand Capacity Resources shall in addition: (i) comply with the measurement and verification requirements and the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures; and (ii) comply with the auditing and rating requirements as detailed in Section III.15.7.1.5.5 and the ISO New England Manuals.

**III.15.7.1.5.4. On-Peak Demand Capacity Resource and Seasonal Peak Demand Capacity Resource Auditing Requirements.**

(a) A summer Passive DR Audit value and a winter Passive DR Audit value must be established for each On-Peak Demand Capacity Resource and Seasonal Peak Demand Capacity Resource in every Capacity Commitment Period during which the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource has an annual or monthly Capacity Supply Obligation.

(b) Summer Passive DR Audit values shall be determined based on data for one or more months of the summer Passive DR Auditing Period (June through August). Winter Passive DR Audit values shall be

determined based on data for one or more months of the winter Passive DR Auditing Period (December through January).

(c) Passive DR Audit values shall be made available to the Market Participant within 20 Business Days following the end of the period for which the audit value is determined by the ISO.

(d) The audit value of an On-Peak Demand Capacity Resource shall be determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the On-Peak Demand Capacity Resource during the Demand Resource On-Peak Hours.

(e) The audit value of a Seasonal Peak Demand Capacity Resource shall be determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the Seasonal Peak Demand Capacity Resource during the Demand Resource Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in a month during the Passive DR Auditing Period, performance during Demand Resource On-Peak Hours in that month may be used.

(f) Passive DR Audit values shall become effective one calendar day after being made available to the Market Participant and remain valid until the earlier of: (i) the next like-season Passive DR Audit value becomes effective or (ii) the end of the following Capability Demonstration Year.

(g) For On-Peak Demand Capacity Resources consisting of Energy Efficiency measures and Seasonal Peak Demand Capacity Resources consisting of Energy Efficiency measures, the ISO shall calculate a summer Passive DR Audit value and a winter Passive DR Audit value in each month of the year. For all other On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources, a Market Participant may request that a summer or winter Passive DR Audit value be determined based on data for, respectively, a summer or winter month outside of the Passive DR Auditing Periods. Such an audit shall not satisfy the Passive DR Audit requirement.

**III.15.7.1.5.5. Additional Demand Capacity Resource Audits.**

The ISO may perform one or both of the following additional audits for a Demand Capacity Resource to establish or verify the capability of the Demand Capacity Resource and its underlying assets and measures.

(a) Level 1 Audit: the ISO shall establish the audit results by conducting a review of records of the Assets and measures to verify that the reported Assets and measures have been installed and are operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.

(b) Level 2 Audit: the ISO shall establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of the Assets and measures. Such an audit may include a random or select sample of facilities and measures.

A level 1 audit is not required to precede a level 2 audit. If the results of the audit indicate that the demand reduction capability of the Demand Capacity Resource is less than or greater than its most recent like-season Passive DR Audit value or Seasonal DR Audit value, then the Demand Capacity Resource's audit value shall be adjusted accordingly.

**III.15.7.1.6. DNE Dispatchable Generator.**

**III.15.7.1.6.1. Energy Market Offer Requirements**.

DNE Dispatchable Generators with a Capacity Supply Obligation must submit offers into the Day-Ahead Energy Market for the full amount of the resource's expected hourly physical capability as determined by the Market Participant. Market Participants with DNE Dispatchable Generators having a Capacity Supply Obligation must submit offers for the Real-Time Energy Market consistent with the characteristics of the resource. For purposes of calculating Real-Time NCPC Charges, DNE Dispatchable Generators shall have a generation deviation of zero.

**III.15.7.1.7. Distributed Energy Capacity Resources with Capacity Supply Obligations.**

**III.15.7.1.7.1. Energy Market Offer Requirements.**

(a) A Market Participant with a Distributed Energy Capacity Resource having a Capacity Supply Obligation shall submit offers for its Distributed Energy Resource Aggregations into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.15.7.1.7.1; for purposes of the following comparisons, the portion of any Demand Reductions Offers or Baseline Deviation Offers not associated with Net Supply shall be increased by average avoided peak

transmission and distribution losses. The sum of the offers must be equal to or greater than the Distributed Energy Capacity Resource's Capacity Supply Obligation whenever the Distributed Energy Resource Aggregations are physically available. If the Distributed Energy Resource Aggregations are physically available at a level less than the Distributed Energy Capacity Resource's Capacity Supply Obligation, the sum of the offers must equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each offer from a Distributed Energy Resource Aggregation made into the Day- Ahead Energy Market shall also meet the following requirement:

(i) the sum of the resource's notification time plus start-up time plus Minimum Run Time (or Minimum Deviation Time or Minimum Reduction Time) plus Minimum Down Time (or Minimum Time Between Deviations or Minimum Time Between Reductions) is less than or equal to 72 hours.

(b) Notwithstanding the foregoing, if the Distributed Energy Capacity Resource comprises Settlement Only Distributed Energy Resource Aggregations, it is not obligated to submit Supply Offers into the Day-Ahead Energy Market and may not submit Supply Offers into the Real-Time Energy Market.

**III.15.7.1.7.2. Requirement that Offers Reflect Accurate Distributed Energy Capacity Resource Operating Characteristics.**

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the then-known capability of the resource.

**III.15.7.1.7.3. Additional Requirements for Distributed Energy Capacity Resources.**

Distributed Energy Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) A Market Participant may not associate an Asset with a non-commercial Distributed Energy Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Distributed Energy Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) Distributed Energy Capacity Resources shall comply with the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

(c) Distributed Energy Capacity Resources shall comply with the auditing and rating requirements as detailed in this Market Rule 1 and the ISO New England Manuals.

(d) For Distributed Energy Capacity Resources, the Seasonal DECR Audit Value shall be established pursuant to Section III.1.7.13.

**III.15.7.2. Resources without a Capacity Supply Obligation.**

A resource that does not have any Capacity Supply Obligation shall comply with the requirements in this Section III.15.7.2 and shall not be subject to the requirements set forth in Section III.15.7.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

**III.15.7.2.1. Generating Capacity Resources without a Capacity Supply Obligation.**

**III.15.7.2.1.1. Energy Market Offer Requirements.**

A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. A Generating Capacity Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

**III.15.7.2.1.1.1. Day-Ahead Energy Market Participation.**

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offered energy clears in the Day-Ahead Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the operating day,

including the obligation to follow ISO Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

**III.15.7.2.1.1.2. Real-Time Energy Market Participation.**

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Real-Time Energy Market. If any portion of the offered energy clears in the Real-Time Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Real-Time Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow ISO Dispatch Instructions. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

**III.15.7.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.**

Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;

(b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Generating Capacity Resources having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

**III.15.7.2.2. Distributed Energy Capacity Resources without a Capacity Supply Obligation.**

**III.15.7.2.2.1. Energy Market Offer Requirements.**

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation is not required to submit offers for the resource into the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant

with a Settlement Only Distributed Energy Resource Aggregation is not permitted to submit an offer for that resource into the Real-Time Energy Market.

**III.15.7.2.2.2. Day-Ahead Energy Market Participation.**

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation may submit an offer into the Day- Ahead Energy Market. If any portion of the offer clears in the Day-Ahead Energy Market, the entire offer, up to the maximum capability offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market so long as it is not a Settlement Only Distributed Energy Resource Aggregation.

**III.15.7.2.2.3. Real-Time Energy Market Participation.**

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation, that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit an offer in the Real-Time Energy Market so long as the resource is not a Settlement Only Distributed Energy Resource Aggregation, and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

**III.15.7.2.2.4. Additional Requirements for Distributed Energy Capacity Resources Having No Capacity Supply Obligation.**

Distributed Energy Capacity Resources without a Capacity Supply Obligation shall comply with the requirements in Section III.15.7.1.7.3.

**III.15.7.2.3. Intermittent Power Resources without a Capacity Supply Obligation.**

**III.15.7.2.3.1. Energy Market Offer Requirements**.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. An Intermittent Power Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

**III.15.7.2.3.2. Additional Requirements for Intermittent Power Resources.**

Intermittent Power Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals; and

(b) Operating Data collection requirements as detailed in the ISO New England Manuals.

**III.15.7.2.4. [Reserved.]**

**III.15.7.2.5. Demand Capacity Resources without a Capacity Supply Obligation.**

**III.15.7.2.5.1. Energy Market Offer Requirements.**

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

Seasonal Peak Demand Capacity Resources and On-Peak Demand Capacity Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

**III.15.7.2.5.1.1. Day-Ahead Energy Market Participation.**

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation may submit a Demand Reduction Offer into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer, up to the Maximum Reduction offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

**III.15.7.2.5.1.2. Real-Time Energy Market Participation**.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit a Demand Reduction Offer in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

**III.15.7.2.5.2. Additional Requirements for Demand Capacity Resources Having No Capacity Supply Obligation**.

Demand Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with Section III.15.7.1.5.3(a) and (b) and with the auditing and rating requirements described in Section III.15.7.1.5.5 and the ISO New England Manuals;

(b) for Active Demand Capacity Resources, complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) for Active Demand Capacity Resources, complying with outage requirements as detailed in the ISO New England Operating Procedures and ISO New England Manuals. Active Demand Capacity Resources having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

**III.15.7.3. Exporting Resources.**

A resource that is exporting capacity not subject to a Capacity Supply Obligation to an external Control Area shall comply with this Section III.15.7.3 and the ISO New England Manuals. Intermittent Power Resources and Demand Capacity Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7 and Section III.1.10.7.A, as applicable.

**III.15.7.4. ISO Requests for Energy.**

The ISO may request that an Active Demand Capacity Resource, a Generating Capacity Resource, or a Distributed Energy Capacity Resource having capacity that is not subject to a Capacity Supply Obligation provide energy for reliability purposes in the Real-Time Energy Market, but such resource shall not be obligated under this Section III.15 by such a request to provide energy from that capacity. If such resource does provide energy from that capacity, the resource shall be paid based on its most recent offer and is eligible for NCPC.

**III.15.7.4.1. Real-Time High Operating Limit.**

For purposes of facilitating ISO requests for energy under Section III.15.7.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

**III.15.8. Capacity Payments and Charges.**

Revenue in the Annual Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.15.8.1 and Capacity Performance Payments as described in Section III.15.8.2, adjusted as described in Section III.15.8.3 and Section III.15.8.4. Market Participants with a Capacity Load Obligation shall be subject to charges as described in Section III.15.8.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.15 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

**III.15.8.1. Capacity Base Payments**.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.15.8.1.1.

**III.15.8.1.1. Payments and Charges Reflecting Capacity Supply Obligations.**

Each resource that has: (i) cleared in an Annual Capacity Auction, except for the portion of resources designated as Self-Supplied Capacity Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.15.8.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Annual Capacity Auction**. For a resource whose offer has cleared in an Annual Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the

Forward Capacity Auction in which the offer cleared, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, and subject to the limitations set forth in Section III.15.2.1.3.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in a Monthly Reconfiguration Auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and the price associated with the Capacity Supply Obligation Bilateral.

**III.15.8.1.2 Export Capacity**

If there are any unobligated Export Offer Segments from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Annual Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows.

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$ ] x [Cleared MWs of Export Offer Segment]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$ ] x [Cleared MWs of Export Offer Segment]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.15.8.5.2.

**III.15.8.2. Capacity Performance Payments.**

**III.15.8.2.1. Definition of Capacity Scarcity Condition.**

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

**III.15.8.2.2. Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.**

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.15.8.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided

for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.15.8.2.2(c), for any On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.15.8.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(ii) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(iii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

(e) A Distributed Energy Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Metered Quantity for Settlement and Reserve Quantity for Settlement of all the components of its constituent Distributed Energy Resource Aggregations; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Based on the Real-Time operational coordination, the resource must follow any distribution system limitation and update its physical parameters accordingly. The Actual Capacity Provided cannot be less than zero.

(i) The Real-Time demand reduction of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response

Baseline of the Demand Response Asset or Distributed Energy Resource associated with the Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

**III.15.8.2.3. Capacity Balancing Ratio.**

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

provided, however, that the Capacity Balancing Ratio shall not exceed a value of 1.0.

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.15.8.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the

Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

**III.15.8.2.4. Capacity Performance Score.**

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Capacity Resource or a Seasonal Peak Demand Capacity Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

**III.15.8.2.5. Capacity Performance Payment Rate.**

The Capacity Performance Payment Rate shall be $3500/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

**III.15.8.2.6. Calculation of Capacity Performance Payments.**

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an

interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

**III.15.8.3. Monthly Capacity Payment and Capacity Stop-Loss Mechanism.**

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.15.8.3.1 and Section III.15.8.3.2 below.

**III.15.8.3.1. Monthly Stop-Loss.**

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the product of the applicable Capacity Auction Offer Price Cap multiplied by the resource's Capacity Supply Obligation for the Obligation Month.

**III.15.8.3.2. Annual Stop-Loss.**

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (ACAcp – ACAsp) – (12 months x ACAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

ACAcp = the Capacity Clearing Price for the relevant Annual Capacity Auction.

ACAsp = the Annual Capacity Auction Offer Price Cap for the relevant Annual Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.15.8.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.15.8.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.15.8.3.2(b).

**III.15.8.4. Allocation of Deficient or Excess Capacity Performance Payments.**

For Capacity Scarcity Conditions as described in Section III.15.8.2.1, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a), (b), and (c) below.

(a) If the sum of all Capacity Performance Payments to all resources subject to a Capacity Scarcity Condition in an Obligation Month is positive, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.15.8.3, the deficiency shall be charged to resources in proportion to the sum of each such resource's positive Capacity Performance Score for the Obligation Month.

(b) If the sum of all Capacity Performance Payments to all resources subject to a Capacity Scarcity Condition in an Obligation Month is negative, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.15.8.3, the excess shall be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.15.8.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.15.8.3, and the remaining excess shall be further allocated to other resources in the same manner as described in this Section III.15.8.4(b).

(c) If a deficiency of Capacity Performance Payments exists due to one or more resources reaching the stop-loss limit described in Section III.15.8.3, the deficiency shall be charged to all resources subject to a Capacity Scarcity Condition in an Obligation Month that have not reached their stop-loss limit (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. If the charge described in Section III.15.8.4(a) or the charge described in this Section III.15.8.4(c) causes a resource to reach the stop-loss limit described in Section III.15.8.3, then the stop-loss limit described in Section III.15.8.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.15.8.4(c).

**III.15.8.5. Charges to Market Participants with Capacity Load Obligations.**

**III.15.8.5.1. Calculation of Capacity Charges.**

For purposes of this Section III.15.8.5.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in rate component (b) of Sections III.15.8.5.1.1 through III.15.8.5.1.8 shall be divided by the number of days in the month to derive a daily settlement value.

**III.15.8.5.1.1. Annual Capacity Auction Charge.**

The ACA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone ACA Costs divided by Zonal Capacity Obligation.

Where:

Capacity Zone ACA Costs, for each Capacity Zone, are the Total ACA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total ACA Costs are the sum of, for all Capacity Zones, Capacity Supply Obligations in each zone (the total obligation awarded to resources in the Annual Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.15.8.5.1.5) multiplied by the applicable clearing price from the auction in which the obligation was awarded to the resource.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

**III.15.8.5.1.2. Monthly Reconfiguration Auction Charge.**

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where:

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the Monthly Reconfiguration Auction in each zone and the applicable Monthly Reconfiguration Auction clearing price, minus the sum of, for all Capacity Zones, any Capacity Supply Obligations shed through the Monthly Reconfiguration Auction in each zone and the applicable Monthly Reconfiguration Auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

**III.15.8.5.1.3. HQICC Capacity Charge.**

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where:

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections III.15.8.5.1.1(b), III.15.8.5.1.2(b), III.15.8.5.1.5(b), III.15.8.5.1.6(b), III.15.8.5.1.7(b), and III.15.8.5.1.8(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

**III.15.8.5.1.4. Self-Supply Adjustment.**

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where:

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied Capacity Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections III.15.8.5.1.1.(b), III.15.8.5.1.2(b), III.15.8.5.1.5(b), III.15.8.5.1.6(b), III.15.8.5.1.7(b) and III.15.8.5.1.8(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

**III.15.8.5.1.5. Intermittent Power Resource Capacity Adjustment.**

The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where:

Intermittent Power Resource Seasonal Variance is the difference between the ACA payments for Intermittent Power Resources in the Obligation Month and the base ACA payments for Intermittent Power Resources.

ACA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to Intermittent Power Resources in the Annual Capacity Auction process for the Obligation Month pursuant to Section III.15.4.2.3, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base ACA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Annual Qualified Capacity procured from Intermittent Power Resources in the

Annual Capacity Auction process, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Zonal Capacity Obligation in all Capacity Zones.

**III.15.8.5.1.6. CTR Transmission Upgrade Charge.**

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where:

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.15.8.5.4.1(f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

**III.15.8.5.1.7. CTR Pool-Planned Unit Charge.**

The CTR Pool-Planned Unit charge is: (a) the total Capacity Load Obligation in all Capacity Zones less the amount of any CTRs specifically allocated pursuant to Section III.15.8.5.4.2, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.15.8.5.4.2.

Where:

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.15.8.5.4.2(b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

**III.15.8.5.1.8. Multi-Year Rate Election Adjustment.**

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity

Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where:

Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that were terminated pursuant to Section III.13.3.4A or Section III.15.A.2.1, or withdrawn pursuant to Section III.15.A.2.3), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where:

Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that were terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the

Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

**III.15.8.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.**

The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation prior to the commencement of each Obligation Month for each Capacity Zone established in the Annual Capacity Auction pursuant to Section III.12.4. The Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

The Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year one year prior to the start of the Capacity Commitment Period to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year one year prior to the start of the Capacity Commitment Period.

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; when all load of a Distributed Energy Resource Aggregation participating as a Storage DARD is load associated with the receipt of electricity from the grid for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each day of the month and each Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above and (ii) the ratio of the sum of the load serving entity's daily Coincident Peak Contributions, to the sum of all load serving entities' daily Coincident Peak Contributions in that Capacity Zone.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each day of the month and each Capacity Zone, adjusted as appropriate to account for any relevant Capacity

Load Obligation Bilaterals, HQICCs, and Self-Supplied Capacity Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource, Demand Response Resource, or a Demand Response Distributed Energy Resource Aggregation.

**III.15.8.5.2.1. Charges Associated with Dispatchable Asset Related Demands.**

Dispatchable Asset Related Demand resources will not receive Annual Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

**III.15.8.5.3. Excess Revenues**.

Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section III.13.3.4A or Section III.15.A.2.1, or withdrawn pursuant to Section III.15.A.2.3, shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

**III.15.8.5.4. Capacity Transfer Rights.**

**III.15.8.5.4.1. Specifically Allocated CTRs Associated with Transmission Upgrades.**

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.15.8.5.1.6.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.15.8.5.1.6.

(e) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine export interface for as long as Casco Bay continues to pay to support the transmission upgrades.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price in the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price in the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. This value will be divided by the number of days in the month to derive a daily settlement value.

**III.15.8.5.4.2. Specifically Allocated CTRs for Pool-Planned Units.**

(a) In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive for each Capacity Commitment Period an allocation of CTRs for each such unit that is the product of: (i) the MW quantity of capacity that the unit cleared in the Annual Capacity Auction associated with the Capacity Commitment Period; and (ii) the municipal utility's ownership entitlements in such unit. The CTRs allocated pursuant to this Section may be designated as self-supply quantities as described in Section III.15.2.9. Municipal utility ownership entitlements are set as shown in the table below and are not transferrable.

| | Millstone 3 | Seabrook | Stonybrook GT 1A | Stonybrook GT 1B | Stonybrook GT 1C | Stonybrook 2A | Stonybrook 2B | Wyman 4 |
|---|---|---|---|---|---|---|---|---|
| Danvers | 0.2627% | 1.1124% | 8.4569% | 8.4569% | 8.4569% | 11.5551% | 11.5551% | 0.0000% |
| Georgetown | 0.0208% | 0.0956% | 0.7356% | 0.7356% | 0.7356% | 1.0144% | 1.0144% | 0.0000% |
| Ipswich | 0.0608% | 0.1066% | 0.2934% | 0.2934% | 0.2934% | 0.0000% | 0.0000% | 0.0000% |
| Marblehead | 0.1544% | 0.1351% | 2.6840% | 2.6840% | 2.6840% | 1.5980% | 1.5980% | 0.2793% |
| Middleton | 0.0440% | 0.3282% | 0.8776% | 0.8776% | 0.8776% | 1.8916% | 1.8916% | 0.1012% |
| Peabody | 0.2969% | 1.1300% | 13.0520% | 13.0520% | 13.0520% | 0.0000% | 0.0000% | 0.0000% |
| Reading | 0.4041% | 0.6351% | 14.4530% | 14.4530% | 14.4530% | 19.5163% | 19.5163% | 0.0000% |
| Wakefield | 0.2055% | 0.3870% | 3.9929% | 3.9929% | 3.9929% | 6.3791% | 6.3791% | 0.4398% |
| Ashburnham | 0.0307% | 0.0652% | 0.6922% | 0.6922% | 0.6922% | 0.9285% | 0.9285% | 0.0000% |
| Boylston | 0.0264% | 0.0849% | 0.5933% | 0.5933% | 0.5933% | 0.9120% | 0.9120% | 0.0522% |
| Braintree | 0.0000% | 0.6134% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| Groton | 0.0254% | 0.1288% | 0.8034% | 0.8034% | 0.8034% | 1.0832% | 1.0832% | 0.0000% |
| Hingham | 0.1007% | 0.4740% | 3.9815% | 3.9815% | 3.9815% | 5.3307% | 5.3307% | 0.0000% |
| Holden | 0.0726% | 0.3971% | 2.2670% | 2.2670% | 2.2670% | 3.1984% | 3.1984% | 0.0000% |
| Holyoke | 0.3194% | 0.3096% | 0.0000% | 0.0000% | 0.0000% | 2.8342% | 2.8342% | 0.6882% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Hudson | 0.1056% | 1.6745% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.3395% |
| Hull | 0.0380% | 0.1650% | 1.4848% | 1.4848% | 1.4848% | 2.1793% | 2.1793% | 0.1262% |
| Littleton | 0.0536% | 0.1093% | 1.5115% | 1.5115% | 1.5115% | 3.0607% | 3.0607% | 0.1666% |
| Mansfield | 0.1581% | 0.7902% | 5.0951% | 5.0951% | 5.0951% | 7.2217% | 7.2217% | 0.0000% |
| Middleborough | 0.1128% | 0.5034% | 2.0657% | 2.0657% | 2.0657% | 4.9518% | 4.9518% | 0.1667% |
| North Attleborough | 0.1744% | 0.3781% | 3.2277% | 3.2277% | 3.2277% | 5.9838% | 5.9838% | 0.1666% |
| Pascoag | 0.0000% | 0.1068% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| Paxton | 0.0326% | 0.0808% | 0.6860% | 0.6860% | 0.6860% | 0.9979% | 0.9979% | 0.0000% |
| Shrewsbury | 0.2323% | 0.5756% | 3.9105% | 3.9105% | 3.9105% | 0.0000% | 0.0000% | 0.4168% |
| South Hadley | 0.5755% | 0.3412% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| Sterling | 0.0294% | 0.2044% | 0.7336% | 0.7336% | 0.7336% | 1.1014% | 1.1014% | 0.0000% |
| Taunton | 0.0000% | 0.1003% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| Templeton | 0.0700% | 0.1926% | 1.3941% | 1.3941% | 1.3941% | 2.3894% | 2.3894% | 0.0000% |
| Vermont Public Power Supply Authority | 0.0000% | 0.0000% | 2.2008% | 2.2008% | 2.2008% | 0.0000% | 0.0000% | 0.0330% |
| West Boylston | 0.0792% | 0.1814% | 1.2829% | 1.2829% | 1.2829% | 2.3041% | 2.3041% | 0.0000% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Westfield | 1.1131% | 0.3645% | 9.0452% | 9.0452% | 9.0452% | 13.5684% | 13.5684% | 0.7257% |

Allocation of CTRs as described in this Section shall expire on December 31, 2040. If a unit listed in the table above retires prior to December 31, 2040, however, allocation of CTRs for such unit shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Annual Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant (collectively, "WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) For any CTRs specifically allocated pursuant to this Section that are not designated self-supply quantities for the Capacity Commitment Period, the municipal utility entitlement holder shall receive a credit reflecting the value of such remaining CTRs. The value of each remaining CTR shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located; and (ii) the remaining MW quantity. This value will be divided by the number of days in the month to derive a daily settlement value.

**III.15.8.5.5. Annual Capacity Market Net Charge Amount.**

The Annual Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charges; (b) its revenues from any applicable specifically allocated CTRs; and (c) any applicable export charges.

**III.15.9. Information Publication and Reporting.**

**III.15.9.1. Publication of Certain Data Prior to the Annual Capacity Auction.**

For each Annual Capacity Auction, no later than one Business Day before the opening of the Annual Capacity Auction Offer Window, the ISO shall publish publicly on its website:

a. which Capacity Zones shall be modeled in the Annual Capacity Auction;
b. the transmission interface limits as determined pursuant to Section III.12.5;
c. which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Annual Capacity Auction;
d. determinations on which new resources have been rejected due to deliverability impacts pursuant to Section III.15.2.3;
e. the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Annual Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;
f. for each resource that submitted a Load-Side Relationship Certification, the following information: the resource technology type; which qualifying circumstance in Section III.A.21.1.4 was asserted in the Load-Side Relationship Certification; the relevant state policy asserted in the Load-Side Relationship Certification, if any; whether the ISO accepted or rejected the Load-Side Relationship Certification; and, consequently, whether the resource was subject to a review for the exercise of buyer-side market power; and
g. which resources are qualified to participate in the Annual Capacity Auction, including resource type, Capacity Zone, and Annual Qualified Capacity.

**III.15.9.2. Publication of Certain Data After Conducting the Annual Capacity Auction**

In addition to the Annual Capacity Auction results information identified by Section III.15.2.11 and Section III.15.4.3 of Market Rule 1, within 15 days of conducting the Annual Capacity Auction, the ISO shall publish publicly on its website:

a. which Capacity Offers, satisfying the requirements of Section III.A.21.1 of Market Rule 1, were not reviewed for an exercise of buyer-side market power because of one of the conditions described in Sections III.A.21.1.1, III.A.21.1.2, or III.A.21.1.4 of Market Rule 1; and the condition met by each such resource;
b. the Internal Market Monitor's determinations made as part of any buyer-side market power review conducted pursuant to Section III.A.21.2 and any Capacity Offer Floor Price determinations made pursuant to Section III.A.21.3 with regard to capacity not previously cleared

in an Annual Capacity Auction or Forward Capacity Auction, and the basis for any such determinations; except that offer price information and any information employed by the Internal Market Monitor in making these determinations related to the potential impact of a Capacity Resource's offer on Capacity Clearing Prices shall not be published publicly;

c. the Internal Market Monitor's determinations regarding Proposed Capacity Offers, including whether the Internal Market Monitor accepted or rejected prices specified in a resource's Proposed Capacity Offer that were subject to Internal Market Monitor review and whether the Internal Market Monitor accepted or rejected the cost components of the resource' offer, which are set forth in Section III.A.22.2.3(a). No offer prices, cost components, or other underlying data shall be published; and,

d. which resources offering capacity not previously offered into an Annual Capacity Auction or Forward Capacity Auction were qualified to participate in the Annual Capacity Auction (this information will include a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations).