October 31, 2014

BY ELECTRONIC FILING

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

RE: **ISO New England Inc. and New England Power Pool, Docket No. ER15-___-000, Market Rule 1 Changes to Integrate Price-Responsive Demand into Reserve Markets**

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("Section 205"),[1] ISO New England Inc. (the "ISO"), joined by the New England Power Pool ("NEPOOL") Participants Committee[2] (together, the "Filing Parties"),[3] hereby electronically submits this transmittal letter and revised Tariff sections to address a series of revisions to the full integration market rules for price-responsive demand. These revisions will (1) permit price-responsive demand to provide Operating Reserves and participate in the Forward Reserve Market on an equal footing with generators and other supply-side resources, (2) simplify the way in which price-responsive demand resources that can push back energy onto the grid from behind-the-meter generators participate in the wholesale electricity markets, and (3) make a number of ancillary and conforming changes that will facilitate the full integration of price-responsive demand into the wholesale electricity markets. These revisions are collectively referred to as the "PRD Reserves Changes." The ISO

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

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

[3] Under New England's RTO arrangements, the rights to make this filing of changes to Market Rule 1 under Section 205 of the Federal Power Act are the ISO's. NEPOOL, which pursuant to the Participants Agreement provides the sole Market Participant stakeholder process for advisory voting on ISO matters, supported the changes reflected in this filing and accordingly, joins in this Section 205 filing.

also submits herewith the supporting testimony of Henry Y. Yoshimura, which is sponsored solely by the ISO (the "Yoshimura Testimony").[4]

As discussed in more detail in Section II, the Filing Parties request the Commission accept the PRD Reserves Changes to be effective on January 12, 2015, which is more than 60 days from the date of this filing.[5]

I. INTRODUCTION

A. *History of PRD in New England*

The PRD Reserves Changes are another in a series of market rule modifications that are intended to move New England toward the full integration of price-responsive demand into the wholesale electricity markets, and is the fulfillment of a commitment the ISO made in 2012 to integrate price-responsive demand into the reserve markets. This series of rule changes began with the August 2011 filing of two sets of Tariff revisions in compliance with Order No. 745,[6] *Demand Response Compensation in Organized Wholesale Energy Markets*.[7] The ISO's compliance filing for Order No. 745 proposed implementing PRD in two stages: rules defining how a demand response resource participates in the New England energy market during an initial "transition period," (referred to herein as the "PRD TP" rules) and integrated rules, which are designed to fully integrate demand response resources into the energy market and will replace the transition period rules starting in June 2017 (referred to herein as the "PRD FI" rules).

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[4] Mr. Yoshimura is the Director of Demand Resource Strategy for the ISO.

[5] The ISO recognizes the uncertainty created by the United States Court of Appeals for the District of Columbia Circuit decision in *Electric Power Supply Ass'n v. Federal Energy Regulatory Commission*, 753 F.3d 216 (D.C. Cir. 2014), and the court's October 20 order staying issuance of the mandate. *See Elec. Power Supply Ass'n v. FERC*, No. 11-1486 (D.C. Cir. Oct. 20, 2014) (per curiam). In light of the stay, the ISO believes that the appropriate course to take at this time is to continue to develop market rules that fully integrate demand response into the wholesale electricity markets on the supply side, an objective which, as discussed in more detail below, the region has been working toward for several years. This effort is necessary to provide Market Participants who have or will be taking on obligations to provide capacity in future commitment periods with certainty as to the markets in which they will participate should the Commission's current jurisdiction over demand response be upheld. Furthermore, seeking to provide certainty at this time does not preclude the ISO from engaging in contingency planning should that be necessary, a task that can and should proceed through the normal ISO development process with input from stakeholders as that process is carried out.

[6] *ISO New England Inc.*, Order No. 745 Compliance Filing, Docket Nos. ER11- 4336-000 and ER11-4336-001 (filed August 19, 2011) (the "August 19, 2011 Filing").

[7] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 76 Fed. Reg. 16,658 (Mar. 15, 2011), FERC Stats. & Regs. ¶ 31,322, *order on reh'g and clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011).

The PRD TP program was implemented in June of 2012, following the development of rules to explain how price-responsive demand would function in the Forward Capacity Market during the transition period.[8] Subsequent to the August 19, 2011 filing of the PRD TP and PRD FI rules, the ISO developed additional market rule enhancements to more fully integrate price-responsive demand for PRD FI. In April 2012, the ISO filed a series of revisions to explain how price-responsive demand would participate in the Forward Capacity Market under PRD FI.[9] The Commission accepted the large majority of this proposal, subject to the ISO making a compliance filing to provide additional explanation on some of the revisions.[10] In June 2013, the ISO filed proposed rule changes to address the treatment of an important class of price-responsive demand resources—those that can "push back" electricity onto the grid from behind-the-meter generators—and proposed further clarifications to the rules for PRD FI rules.[11] The Commission accepted these proposed revisions.[12]

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[8] *ISO New England Inc. and New England Power Pool*, Price Responsive Demand FCM Conforming Changes, Docket No. ER12-947-000 (filed January 31, 2012) (the "January 31, 2012 Filing"). On April 13, 2012, a series of clarifying changes to the PRD TP rules and the Forward Capacity Market rules were also filed. *ISO New England Inc. and New England Power Pool*, Market Rule 1 Clarifications to the Transition Period Rules for Price-Responsive Demand, Docket No. ER12-1550-000 (filed April 13, 2012) (the "April 13, 2012 Filing"). All three sets of PRD TP rules (*i.e.*, the transition period rules filed in the August 19, 2011 Filing, the conforming Forward Capacity Market rule modifications filed in the January 31, 2012 Filing, and the clarifications filed in the April 13, 2012 Filing), were accepted by the Commission and became effective June 1, 2012. *See* 138 FERC ¶ 61,042 (2012) ("January 19, 2012 Order"); Letter order Accepting Price-Responsive Demand FCM Conforming Changes, Docket No. ER12-947-000 (issued April 17, 2012); Letter Order Accepting Clarifications to the Transition Period Rules for Price Responsive Demand, Docket No. ER12-1550-000 (issued May 29, 2012).

[9] *ISO New England Inc.*, Market Rule 1 Price Responsive Demand FCM Conforming Changes for Full Integration, Docket No. ER12-1627-000, (April 26, 2012) ("April 26, 2012 Filing").

[10] *ISO New England Inc.*, Order on Proposed Tariff Revisions, 142 FERC ¶ 61,027 (2013) ("January 14, 2013 Order"). On January 15, 2013, the Commission issued an Errata Notice that deleted Paragraph 32 in its entirety and corrected Paragraph 33. All references to the January 14 Order are to the corrected version. In addition, the Commission rejected the ISO's proposed treatment of net supply in the Forward Capacity Market, "without prejudice to ISO-NE filing revised Tariff language to clarify its rules regarding demand response resources that provide capacity through both demand reductions and behind-the-meter generation." *See* January 14, 2013 Order at P 43.

[11] *ISO New England Inc. and New England Power Pool*, Market Rule 1 Clarifications to the Full Integration Rules for Price-Responsive Demand and Revisions to Address the Treatment of Net Supply, Docket No. ER13-1742-000 (filed June 21, 2013) (the "June 21, 2013 Filing").

[12] *ISO New England Inc. and New England Power Pool*, Order on Proposed Tariff Revisions, 144 FERC ¶ 61,140 (2013).

B. *Revisions to Integrate Price-Responsive Demand into Reserve Markets for PRD FI*

In its April 2012 filing of Forward Capacity Market changes for PRD FI, the ISO stated its commitment to "work to develop market rules to allow demand response resources that participate in the energy market to participate in the reserve market coincident with the implementation of the fully integrated PRD rules in June 2017, and [to] obtain stakeholder input on the proposed rules through the stakeholder process."[13] Consistent with this commitment, the ISO has developed the PRD Reserves Changes, which will enable Demand Response Resources to provide Operating Reserves and to participate in the Forward Reserve Market with the full integration of Demand Response Resources into the energy markets in June 2017.

The PRD Reserves Changes also contain a series of conforming changes to the market rules to support the integration of demand response into the wholesale electricity markets. Thus, while the existing version of Appendix E2 contains the market rules for the full integration of price-responsive demand into the energy market, a number of supplementary changes must be made to the main body of energy market rules in Sections III.1 through III.7 of Market Rule 1 to recognize the participation of Demand Response Resources in the energy market. Changes are also being made to the existing rules in Section III.8A and III.8B for calculating Demand Response Baselines, so that the availability of Operating Reserves from Demand Response Resources can be accurately quantified.

Finally, the PRD Reserves Changes propose a simplified approach to the way in which Demand Response Resources with behind-the-meter generation that are able to produce Net Supply (i.e., inject energy into the electric grid) are accounted for and compensated. These revisions do not change whether and the extent to which Net Supply can participate (or receive compensation) in the wholesale electricity markets under PRD FI, but only how Net Supply is entered into the markets, how the Net Supply is accounted for in clearing and operating the system, and the way in which the settlement calculations are performed.

Integrating Demand Response Resources into the existing Operating Reserves and Forward Reserve Market structures facilitates the objectives of allowing Market Participants to supply energy, capacity and reserves to the market under common product definitions, take on comparable obligations for the market within which they participate, and receive the same price for the products they deliver.[14] In such a market structure, the dispatch of Resources to provide energy and the designation of Resources to provide Operating Reserves can be co-optimized to produce the most efficient market outcome.[15]

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[13] April 26, 2012 Filing, at p. 4.

[14] Yoshimura Testimony at pp. 9-10.

[15] *Id.*

Furthermore, expanding the potential for additional resources to supply comparable energy and Operating Reserve services in real time and on a forward basis can provide for a more reliable electric system and increases competition among the suppliers of those services.[16]

II. REQUESTED EFFECTIVE DATE

The Filing Parties request that the Commission accept the PRD Reserves Changes as filed, without suspension or hearing, to be effective on January 12, 2015, which is more than 60 days from the date of this filing.[17]

The Filing Parties are requesting this effective date in order to have the PRD Reserves Changes in place before Market Participants submit offers for the 9th Forward Capacity Auction ("FCA9"), scheduled for February 2015. For participants submitting offers for auctions in the three-year Forward Capacity Market, it is important to understand other potential sources of revenues, and the obligations incurred to achieve those revenues, in the wholesale electricity markets. Having the PRD Reserves Changes in place before the February 2015 auction will provide Market Participants with time to consider the impacts of these rules before finalizing offers for the auction.

This same approach has been taken with prior sets of market rule changes that address the integration of price-responsive demand into the energy market, as well as conforming capacity market rule changes. Thus, the rules that address the full integration of Demand Response Resources in the energy market, which is scheduled to commence on June 1, 2017, are in effect now in Appendix E2 of Market Rule 1. However, since, Demand Response Resources cannot participate in the energy market or begin providing capacity in the Forward Capacity Market until June 1, 2017 by definition,[18] those rules are effectively not operational until June 1, 2017. The same is true of the Demand Response Baseline rules (Section III.8B) and the rules that address the role of Demand Response Resources in the Forward Capacity Market. By having these rules in place now, Market Participants have a clear understanding of the rules and requirements that will apply for price-responsive demand once full integration is implemented in June 2017.

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[16] *Id*.

[17] 18 C.F.R. § 35.3 (2013).

[18] Section I.2.2 defines Demand Response Resource as "an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017."

III. DESCRIPTION OF THE FILING PARTIES; 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 with the New England Participating Transmission Owners. In its capacity as an RTO, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Council ("NERC").

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 430 members. The Participants include all of the electric utilities rendering or receiving service under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, demand resource providers, developers and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission,[19] the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, "NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff."

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

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IV. STANDARD OF REVIEW

These changes are being submitted pursuant to Section 205, which "gives a utility the right to file rates and terms for services rendered with its assets."[21] Under Section 205, the Commission "plays 'an essentially passive and reactive role'"[22] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[23] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable - and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[24] The changes proposed herein "need not be the only reasonable methodology, or even the most accurate."[25] As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.[26]

V. OVERVIEW OF THE PRD RESERVES CHANGES

To integrate price-responsive demand into the Operating Reserves structure and the Forward Reserve Market, the ISO undertook a comprehensive review of the market rules. This review produced a large number of changes, the majority of which are required to allow Demand Response Resources to provide reserve on a comparable

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[20] 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.

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

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

[23] *Id.* at 9.

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

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

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

footing with other resource-types, and the remainder of which help improve the overall quality of PRD FI and the Tariff. The changes are summarized in this transmittal letter and are reviewed in detail in the Yoshimura Testimony. They are grouped into the following sections: (A) changes to implement a "common dispatch model" for Demand Response Resources that are capable of producing Net Supply, which is necessary to allow the ISO to properly account for reserves from these resources, (B) changes to integrate Demand Response Resources into the existing Operating Reserves structure, (C) changes to permit Demand Response Resources to participate in the Forward Reserve Market, (D) changes to the auditing rules for Demand Response Resources, and (E) a number of ancillary market rule changes that improve PRD FI and the Tariff.

A. *Changes to the Modeling of Demand Response Assets that Can Produce Net Supply*

The PRD Reserves Changes implement a "common dispatch model" for Demand Response Resources that are capable of producing Net Supply. Under the existing market rules for PRD FI, a single facility that can reduce load from the electric grid and inject energy into the electric grid (*i.e.*, provide Net Supply) is modeled as two assets: a Demand Response Asset that reduces load from the electric grid, and a Net Supply Generator Asset that provides Net Supply to the electric grid. Under the proposed common dispatch model, such a facility is modeled as a single Demand Response Asset, which then eliminates the need to create a separate Net Supply Generator Asset to model Net Supply in the energy market.

The common dispatch model provides the platform that will allow reserves to be properly accounted for when provided by a Demand Response Resource. Accounting for demand reduction from a single asset, rather than from two distinct demand response and generation assets, removes the potential for over-estimating available reserves from a resource that can provide Net Supply. The two-asset model permits a potential over-counting of reserves because it does not account for the inter-temporal dependency between the demand response asset and the generator asset—*i.e.*, it does not account for the fact that generation cannot be provided to the system until the load at the facility is first reduced to a level lower than the output of the generator. Failing to account for this inter-temporal dependency allows for potential over-counting of reserves because, under resource accounting, the capability of each of the two assets to provide reserves is evaluated independently.[27]

Under the common dispatch model, the *demand reduction* produced by a Demand Response Asset is the sum of (1) the *reduced load* from the electric grid and (2) any *Net Supply* provided to the electric grid as measured at the asset's Retail Delivery Point. For reserve accounting, the demand reduction potential for a Demand Response Asset takes account of the inter-temporal dependency between the two asset-types, so that the reserve

[27] *See* the Yoshimura Testimony, at pp. 20-22, for an example of how this would occur.

capability from the Net Supply is factored in only *after* load has been reduced from the electric grid (including the time it takes to reduce that load) and is accounted for.[28]

In his supporting testimony, Mr. Yoshimura explains each of the Tariff changes that are being proposed to implement the common dispatch model. These changes remove the concept of a Net Supply Generator Asset being "associated with" a Demand Response Resource, and replace it with, simply, references to a Demand Response Resource, or references to a Demand Response Asset that can produce Net Supply. Changes are being made to the defined terms, to the Forward Capacity Market rules, the energy market rules for PRD FI, and the Demand Response Baseline rules.[29]

B. *Establishing Rules Regarding How Demand Response Resources Provide Real-Time Operating Reserves*

The PRD Reserves Changes integrate Demand Response Resources into the existing co-optimized energy and real-time Operating Reserves market structures. These rule changes are not intended to change the existing structure for addressing Operating Reserves. Instead, the rule changes add specificity on issues that are unique to Demand Response Resources, so that they can provide reserves under the existing structure. These changes are summarized here and addressed more fully in Mr. Yoshimura's testimony.

<u>Additional Reserve-Related Offer Parameters</u>. To provide Operating Reserves from an off-line state, a Market Participant must have an Offered CLAIM10 and/or an Offered CLAIM30 value in its energy market offer. The Offered CLAIM10 value represents the amount of 10-minute reserve available from a resource. The Offered CLAIM30 value represents the amount of 30-minute reserve available from a resource.[30] Therefore, the definitions of Offered CLAIM10 and Offered CLAIM30 in Section I.2.2, as well as the listing of offer parameters for Demand Response Resources in Section III.E.2.3, are being modified to allow the Market Participant of a Demand Response Resource to submit an Offered CLAIM10 and/or an Offered CLAIM30 value to represent

[28] In his supporting testimony, Mr. Yoshimura provides an example of how the common dispatch model would function for reserve accounting. *See* the Yoshimura Testimony, at pp. 22-23. As Mr. Yoshimura explains, the common dispatch model also achieves two important objectives of the two-asset model: avoiding the potential for double-counting Net Supply, and facilitating the correct accounting for average avoided peak distribution losses. *See* Yoshimura Testimony at pp. 23-27.

[29] Yoshimura Testimony at pp. 27-31.

[30] Under the existing market rules, in particular as reflected in the CLAIM10/30 rules in Section III.9.5.3, the Offered CLAIM10/30 values of a Resource are capped at values that reflect the Resource's performance during a CLAIM10/30 audit, which are adjusted over time based on the Resource's actual performance in response to dispatch.

the amount of 10-minute and/or 30-minute reserve that the Market Participant of an undispatched Demand Response Resource is willing to offer.[31]

Real-Time Reserve Designation and Settlement.[32] The manner in which Demand Response Resources will be designated to provide Operating Reserves will be identical to the manner in which other resources, such as Generator Assets, are presently designated to provide Operating Reserves. To meet this objective, the terms "Demand Response Resource" and "demand reduction" are being incorporated in various places throughout the Operating Reserve rules and related definitions,[33] and Section III.9.2.2 on locational reserves is being modified to explicitly recognize Demand Response Resources in setting the locational reserve requirements. In addition, certain physical characteristics that distinguish Demand Response Resources from generation resources must be recognized to fully address real-time reserve designation and settlement for Demand Response Resources:

- The manner in which a Generator Asset is designated to provide Operating Reserves differs based on whether the generator is "off-line" or "on-line." The proposed market rules use somewhat different terminology for Demand Response Resources. A Demand Response Resource that has been "*dispatched*" to provide a portion or all of its demand reduction is similar to a generator that is "on-line." A Demand Response Resource that is "*not dispatched*" or "*undispatched*" (*i.e.*, has not received a commitment or Dispatch Instruction[34]) is equivalent to a generator that is "off-line."

- To provide Operating Reserves from an off-line state, a Generator Asset must meet the definition of a Fast Start Generator. Accordingly, the ISO proposes a new defined term in Section I.2.2—Fast Start Demand Response Resource—and is integrating this term into the appropriate sections of the Tariff, which allow Demand Response Resources to provide Operating Reserves from an undispatched state. A Fast Start Demand Response Resource must satisfy

[31] *See* the Yoshimura Testimony at pp. 32-33.

[32] These changes are discussed in greater detail in Mr. Yoshimura's supporting testimony at pp. 33-39.

[33] The defined terms for Operating Reserve products in Section I.2.2 (i.e., Ten-Minute Non-Spinning Reserve ("TMNSR"), Ten-Minute Spinning Reserve ("TMSR"), and Thirty-Minute Operating Reserve ("TMOR")) are each being modified to include Demand Response Resources as a type of resource that can provide Operating Reserves. Sections III.10.1.1 and III.E2.1.1 are being clarified so that Demand Response Resources are identified as a type of resource that can be designated to provide Operating Reserves.

[34] The definition of Dispatch Instruction in Section I.2.2 is being modified to incorporate the dispatch of a Demand Response Resource based upon its Demand Reduction Offer.

requirements that are equivalent to comparable requirements for a Fast Start Generator.[35]

- Changes are being made to the definition of Ten-Minute Spinning Reserve ("TMSR") to make clear that a Demand Response Resource that has a behind-the-meter generator whose output can be controlled cannot provide TMSR. A resource that is to provide TMSR must be synchronized to the grid (*i.e.*, spinning), and it cannot be readily ascertained that a resource that provides reserves using a behind-the-meter generator is synchronized to the grid.[36]

- The defined terms for Ten-Minute Non-Spinning Reserve ("TMNSR") or Thirty-Minute Operating Reserve ("TMOR") in Section I.2.2 are being modified to recognize that a Demand Response Resource provides TMNSR or TMOR by providing a demand reduction (rather than energy output) within ten or thirty minutes from the request of the ISO.

<u>Dispatch Zone and Reserve Zone Registration</u>. The revisions include a requirement that all Demand Response Assets associated with a Demand Response Resource be located within a single Dispatch Zone and Reserve Zone. This change is necessary to address the way in which reserve pricing is established. Demand Response Resources mostly consist of aggregations of individual Demand Response Assets located within the same Dispatch Zone. However, the market for reserves varies by Reserve Zone, particularly in the Forward Reserve Market. Accordingly, to provide reserves and participate in the Forward Reserve Market, Demand Response Assets that comprise a Demand Response Resource must be located in the same Reserve Zone.[37]

<u>Telemetry Requirements for Providing 10-Minute Reserves</u>. Changes to the telemetry requirements for Demand Response Resources are required to meet the objective of providing 10-minute reserves. Specifically, if a Demand Response Resource wants to provide 10-minute Operating Reserves, it must provide at least one-minute interval data in real time for each Demand Response Asset associated with the Demand Response Resource. While the current requirement of five-minute data for Demand Response Resources is sufficient for the provision of energy and 30-minute reserves, the 15-minute area control error ("ACE") recovery requirement necessitates that the ISO

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[35] For a listing of these requirements, see the definition of Fast Start Demand Response Resource and the Yoshimura Testimony at pp. 36-37. This term is being integrated into sections of the Tariff that address the treatment of fast start resources for the provision of reserves, in Sections III.2.4; III.9.5.2; and III.9.7.2.

[36] Northeast Power Coordinating Council ("NPCC") standards provide that a Demand Response Resource that must start a behind-the-meter generator may not provide TMSR. NPCC Directory #5, Section 5.15(b).

[37] *See* Yoshimura Testimony at pp. 40-41. This change is reflected in Sections III.E2.1.1, III.E2.1.3, III.E2.1.4, and III.2.7A.

know as soon as possible if resources providing 10-minute reserves have responded to a Dispatch Instruction when activated. The one-minute data requirement will allow the ISO to determine whether the resource has responded in time to allow for the recovery of ACE and avoidance of a NERC violation.[38]

Ancillary Changes for TMSR, TMNSR and TMOR. To allow Demand Response Resources to be designated to provide TMSR, TMNSR, and TMOR in Real-Time, a number of ancillary rule changes are required:

- Section III.1.7.19 on ramping capability is being updated to include parallel ramping requirements for Demand Response Resources (*i.e.*, a Demand Response Resource must be able to change its demand reduction at the ramp rate specified in its Offer Data);
- Section III.2.7A on the calculation of Real-Time Reserve Clearing Prices is being updated to reflect that Demand Response Resources will provide Operating Reserves, with no changes to the clearing price calculation methodology;
- Section III.10.1.1 on Real-Time Reserve Designation is being updated to reflect that the designation must be determined for Demand Response Resources providing Operating Reserves, again with no change to the current calculation methodology; and
- Section III.E2.1.1 on Demand Response Resource registration is being updated to reflect that the resource may be registered to provide reserves as well as to provide energy.

C. *Changing the Demand Response Baseline Adjustment Factor*

In addition to real-time telemetry and energy offer parameters, an estimate of expected demand, absent a Dispatch Instruction to reduce demand, is needed to determine the real-time capability of a Demand Response Resource to provide energy and reserves and to quantify the Demand Response Resource's response to a Dispatch Instruction. A Demand Response Resource's baseline, which represents the level at which the Demand Response Resource is expected to consume energy during the Operating Day when not being dispatched by the ISO to reduce demand, can serve as the estimate of expected demand.

The current Demand Response Baseline calculation methodology in Section III.8B.5 adjusts the baseline once a day, after the Operating Day is over, to account for variations in demand on the day for which the baseline is being calculated.[39] However, a

[38] *See* Yoshimura Testimony at pp. 41-44. This revision to the metering requirements for resources providing 10-minute reserves is addressed in Section III.E2.2.2.

[39] For example, the weather on a given Operating Day may be more extreme relative to the weather on previous days from which meter data were used to compute the baseline.

baseline adjustment that is calculated and applied after the Operating Day is over does not facilitate the determination of a Demand Response Resource's availability and performance in real time, which is the value needed for use in assessing the resource's reserve capability. As a result, the estimated real-time availability of a Demand Response Resource to provide reserves during the Operating Day and/or the calculated real-time performance of a Demand Response Resource if dispatched to provide energy could be significantly over or under estimated if the current baseline adjustment mechanism is utilized.[40] For this reason, a change to the baseline adjustment mechanism is needed to provide a value that is meaningful in the calculation of a Demand Response Resource's real-time availability and performance during the Operating Day.

Under the proposed changes, a Demand Response Resource's availability to provide reserves in real time will be forecasted using historical interval meter data, which will then be adjusted throughout the Operating Day using 5-minute real-time telemetry data. The initial estimated demand forecast will be computed using the method presently in the Demand Response Baseline rules for PRD FI.[41] However, rather than updating the baseline once a day *after* the Operating Day is over, real-time telemetry data received during the Operating Day will be used to adjust the demand forecast at various points throughout the Operating Day. The adjustment procedure will be performed frequently and will be based on telemetry data from recent historical intervals.

The adjustment will be calculated every 15 minutes throughout the operating day, using three five-minute meter data intervals taken from the three intervals that start 25 minutes before, and end 10 minutes before, the quarter hour interval when the adjustment calculation is performed.[42] In his supporting testimony, Mr. Yoshimura describes the analysis performed to establish the frequency of the adjustment and the duration and proximity of the meter data used in the calculation relative to the time for which the adjustment is being calculated.[43] He explains that this adjustment calculation was chosen because, under the analysis performed, "real-time adjustments perform better (i.e., create an adjusted Demand Response Baseline that more accurately reflects actual demand) when proximity is closer, duration is shorter, and the adjustment is recalculated frequently throughout the Operating Day rather than only once a day."[44]

D. *Integrating Demand Response Resources into the Forward Reserve Market*

[40] Yoshimura Testimony at pp. 45-46.

[41] These changes are being made to Section III.8B.5 of the PRD FI baseline calculation rules.

[42] Yoshimura Testimony at pp. 49-50. Additional details are provided on how the adjustment will be calculated when the Demand Response Resource is dispatched. *Id*.

[43] *Id*. at pp. 47-49.

[44] *Id*. at p. 49.

The PRD Reserves Changes modify the Forward Reserve Market rules in Section III.9 to allow Market Participants with Demand Response Resources to participate in the Forward Reserve Market ("FRM") and receive compensation for such participation. Similar to the market rule changes for Operating Reserves, no changes to the basic design of the FRM are proposed. The rule changes described herein integrate Demand Response Resources into the existing FRM structure by revising the FRM eligibility provisions and the resource performance and compensation provisions. Revisions to the FRM auditing rules (*i.e.*, the CLAIM10/CLAIM30 auditing rules) are addressed below in Section E.[45]

<u>FRM Eligibility Requirements for Demand Response Resources</u>.[46] Eligibility requirements for Demand Response Resources mirror the requirements for other resource types that can participate in the FRM, but are modified as necessary to address the unique features of a demand resource. Thus, the eligibility rules in Section III.9.5.2 are being modified to recognize that Demand Response Resources that have not been dispatched can provide the same FRM products as generation resources that are in an off-line state, and Demand Response Resources that have been dispatched can provide the same FRM products as generators that are in an on-line state. Furthermore, a requirement is added that the Demand Response Resource providing reserves from an undispatched state be a Fast Start Demand Response Resource, comparable to the analogous requirement for generators. Finally, the eligibility provision for resources participating in the Forward Capacity Market (which requires that they comply with provisions in Section III.13.6.1.1.2 to reflect accurate generating capacity resource operating characteristics) is updated to cross-reference the comparable provision, Section III.13.6.1.5.2, for Demand Response Resources.

<u>FRM Performance Measurement and Compensation for Demand Response Resources</u>.[47] The PRD Reserves Changes treat Demand Response Resources like other resources when measuring performance and determining compensation for participating in the FRM. This means that Market Participants with Demand Response Resources assigned to meet Forward Reserve Obligations will be paid at the same compensation rate, will be assessed comparable charges for non-performance, and will forego any Real-Time Reserve payment for MWs compensated as Forward Reserve.[48]

Changes to Section III.9.6 are being made to incorporate Demand Response Resources into offer and dispatch requirements for Forward Reserve Resources, the formula for determining the Forward Reserve Threshold Price ("FRTP"), above which Forward Reserve Resources must be offered into the energy market, and the calculation

[45] *Id*. at p. 51.

[46] These changes are discussed in the Yoshimura Testimony at pp. 52-54.

[47] These changes are discussed in the Yoshimura Testimony at pp. 54-61.

[48] Yoshimura Testimony at pp. 54.

of Forward Reserve Qualifying Megawatts and Forward Reserve Delivered Megawatts.[49] Changes to the penalty calculation provisions in Section III.9.7 are made to incorporate Demand Response Resource performance into the calculation methodologies for Failure-to-Reserve Penalties and Failure-to-Activate Penalties, which are the two penalty-types assessed in the Forward Reserve Market.[50]

As Mr. Yoshimura explains in his supporting testimony, some of the complexity required to integrate price-responsive demand into the performance measurement and settlement calculations for the FRM is a result of a unique feature of the way in which price-responsive demand is compensated.[51] Unlike other Forward Reserve Resources, Demand Response Resources perform by reducing load from the grid, injecting energy into the grid (through Net Supply), or a combination of the two.[52] The portion of a Demand Response Resource's performance that is not associated with Net Supply is subject to the "gross up" for avoided peak distribution losses.[53] For this reason, the measurement and compensation of a Demand Response Resource in the FRM must distinguish between performance that results from a reduction in load and performance that results from Net Supply.

E. *Auditing Demand Response Resources*

The PRD Reserves Changes integrate Demand Response Resources into the existing framework that is used to calculate and audit the 10-minute and 30-minute reserve capability of resources that provide Operating Reserves and participate in the Forward Reserve Market. These values are referred to as the CLAIM10 and CLAIM30 values of a reserve resource. The changes also specify operating parameter auditing requirements for Demand Response Resources, comparable to operating parameter auditing requirements for generators, and make other relatively minor changes to the Demand Response Resource capacity market auditing rules.

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[49] These changes are addressed in detail in the Yoshimura Testimony at pp. 55-58.

[50] These changes are addressed in detail in the Yoshimura Testimony at pp. 58-61.

[51] Yoshimura Testimony at pp. 54-55.

[52] Load reductions and Net Supply provided by a Demand Response Resource are measured at the Retail Delivery Points of each of the resource's constituent Demand Response Assets.

[53] Crediting load reductions for average avoided peak distribution losses was proposed by the ISO in response to Order No. 745. This practice was affirmed by the Commission in *ISO New England*, 138 FERC ¶ 61,042 (2012); *ISO New England*, 142 FERC ¶ 61,027 (2013) at PP 12, 52, 56-57; *ISO New England*, 144 FERC ¶ 61,140 (2013) at P 18; *ISO New England*, 146 FERC ¶ 61,175 (2014) at PP 2, 8, 29. As Mr. Yoshimura explains, the gross up is applied as part of the settlement process, rather than as part of the reserve designation process, to avoid over-estimating the amount of reserves that are available in real time at a specific location. *See* Yoshimura Testimony at pp. 26-27.

CLAIM10/30 Auditing Requirements. Under Section III.9.5.3, a Resource that provides reserves from an off-line state must establish, through an audit, its ability to provide power within 10 or 30 minutes. A resource's CLAIM10 value reflects the amount of power it is able to provide within 10 minutes, and a resource's CLAIM30 value reflects the amount of power it is able to provide within 30 minutes. Once these values are established via an audit, a CLAIM10/30 "performance factor" is used to adjust the initial CLAIM10/30 audit values based upon a resource's ability to achieve its offered CLAIM10/30 from an off-line state during actual performance. A resource's CLAIM10 or CLAIM30 performance factor is established based upon the 10 most recent ISO-issued initial electronic startup Dispatch Instructions.

Incorporating Demand Response Resources into the CLAIM10/30 audit requirements requires making relatively modest revisions to the applicable market rules to reflect the distinctive way in which Demand Response Resources function and provide energy relative to generation resources.[54] Thus, for example, the modifications add the term "demand reduction" and "demand-reduction level" wherever the terms "output" and "output level" are used, and a clarification is being made to the definition of the term "Dispatch Rate" to reflect that a Demand Response Resource offers to reduce demand rather than offering an output level. As Mr. Yoshimura explains in his testimony, each aspect of the CLAIM10/30 audit regime is modified to provide comparable rights and obligations for Demand Response Resources.[55]

Demand Response Resource Parameter Auditing Requirements.[56] Section III.1.5.2 allows the ISO to audit any Supply Offer parameter that impacts the ability of a Generator Asset to provide real-time energy or reserves. As resources capable of providing energy and reserves, comparable parameter auditing provisions should also be developed for Demand Response Resources. Accordingly, requirements are being added to Section III.1.5.2 to allow the ISO to audit the offer parameters of Demand Response Resources that are analogous to Generator Asset Supply Offer parameters. These include the parameters Maximum Reduction, Demand Response Resource Ramp Rate, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, CLAIM10, and CLAIM30. Demand Response Resource terminology is also being integrated into the existing provisions that address how these audits will be performed, consequences to a Market Participant based on a resource's performance in an audit, and the procedures for restoring a parameter value after audit.

Demand Response Resource Audit Requirements in the Forward Capacity Market.[57] The PRD Reserves Changes also make a number of clarifications to the

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[54] These changes are addressed in detail in the Yoshimura Testimony at pp. 61-66.

[55] *Id*.

[56] These changes are addressed in detail in the Yoshimura Testimony at pp. 66-67.

[57] These changes are addressed in detail in the Yoshimura Testimony at pp. 67-71.

seasonal capacity audit rules in Sections III.13.6.1.5.4.2 and III.13.6.1.5.4.3.3.1. Section III.13.6.1.5.4.2 is being clarified so that Demand Response Resources associated with a Demand Response Capacity Resource will not have to be audited simultaneously. This treatment is appropriate because, during normal (including capacity-deficient) operating circumstances, individual Demand Response Resources associated with a Demand Response Capacity Resource will not necessarily be simultaneously dispatched when called upon to provide energy. Section III.13.6.1.5.4.3.3.1 is being modified to allow for additional options by which to establish Seasonal DR Audit values.

F. *Ancillary Market Rule Changes*

The PRD Reserves Changes also include a number of ancillary market rule changes. These changes are summarized here and are explained in detail in Mr. Yoshimura's testimony.

The PRD Reserves Changes integrate into the Demand Response Baseline rules for PRD FI three sets of baseline rule changes that have been made to the PRD TP rules and are equally applicable for the full integration of demand response into the wholesale markets. These changes include (1) establishing rules for the Demand Response Baseline of Demand Response Assets experiencing a scheduled or a forced curtailment,[58] (2) establishing rules for resetting Demand Response Baselines,[59] and (3) establishing rules to constrain the adjusted Demand Response Baseline of Demand Response Assets capable of producing Net Supply.[60]

The PRD Reserves Changes also modify the metering requirements in Section III.E2.2.2 for Demand Response Assets with behind-the-meter generation.[61] Rather than requiring that all behind-the-meter generators be metered separately from the facility load, as the current rule contemplates, the modifications require metering only where the generator's output is controllable. As Mr. Yoshimura explains, the metering requirement was put in place to address potential baseline manipulation concerns. However, manipulation is only possible where the facility owner is able to control the output of the generator.[62] For many behind-the-meter generators whose output cannot be controlled, such as a large number of small solar installations, separately metering the generator is unnecessary.[63]

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[58] These changes are addressed in detail in the Yoshimura Testimony at pp. 72-76.

[59] These changes are addressed in detail in the Yoshimura Testimony at p. 76.

[60] These changes are addressed in detail in the Yoshimura Testimony at pp. 77-78.

[61] These changes are addressed in detail in the Yoshimura Testimony at pp. 78-82.

[62] Yoshimura testimony at pp. 80-82.

[63] *Id*.

The PRD Reserve Changes also make a number of other ancillary changes to metering requirement rules in Sections III.13.1.4.3.2, III.E2.2.1, III.E2.2.2, III.E2.2.3 and III.E2.2.4. These changes differentiate telemetry from revenue quality metering and implement a number of improvements to the existing metering requirements. For Market Participants that install their own revenue quality meters on Demand Response Assets, rather than use the distribution company's meter, provisions are being added in Section III.E2.2.1 that require the Market Participant to validate and provide documentation to the ISO that any difference between the values recorded by the Market Participant's meter and the values recorded by the distribution company's billing meter is within an acceptable tolerance range.[64] Similar quality control requirements for telemetry metering are being added in Section III.E2.2.2.[65] In addition, Sections III.E1.2.1 and III.13.1.4.3.2 are being modified to mandate (rather than provide the option) the use of five-minute data. This modification is necessary given that the ISO's baseline-telemetry system is designed to use five-minute interval data only.[66]

Finally, in developing the PRD Reserves Changes, the ISO conducted a comprehensive review of the market rules, and as a result is making several conforming and/or non-substantive market rule changes to further clarify the Tariff. These changes are detailed in Mr. Yoshimura's supporting testimony.[67]

VI. STAKEHOLDER PROCESS

NEPOOL voted on portions of the package of PRD Reserves Changes separately through the complete Participant Processes. At its September 16, 2014 meeting, the NEPOOL Reliability Committee voted unanimously to recommend that the NEPOOL Participants Committee support the revisions to Market Rule 1, Section III.9.5.3 and Market Rule I, Section III.1.5.2 to support implementation of CLAIM10/CLAIM30 auditing and ISO Initiated Parameter Auditing. At its September 3-4, 2014 meeting, the NEPOOL Markets Committee voted to recommend that the NEPOOL Participants Committee support the remainder of the PRD Reserves Changes. [68] Subsequent to the consideration by the Markets Committee and Reliability Committee, the ISO made minor modifications to the PRD Reserves Changes, so that a slightly modified version was presented to the NEPOOL Participants Committee for its review and vote at its October

[64] Yoshimura Testimony at pp. 82-84. Section III.E2.2.1(d) will also require Market Participants to provide documentation to the ISO of any inaccuracies found in distribution company meter data and of any communications with the distribution company to address these inaccuracies.

[65] These changes are addressed in detail in the Yoshimura Testimony at p. 84.

[66] Yoshimura Testimony at p. 84.

[67] *Id*. at pp. 85-91.

[68] During the NEPOOL Markets Committee vote at its September 3-4 meeting, there was one opposition noted within the Generation Sector and several abstentions.

3, 2014 meeting. At this meeting the Participants Committee voted to support the PRD Reserves Changes with oppositions and abstentions noted.[69]

For purposes of this filing, NEPOOL states that, given the current status of the D.C. Circuit decision vacating Order No. 745, its vote and the vote of any individual member taken at the October 3, 2014 meeting in support of the PRD Reserves Changes was with the understanding that the proposed changes would be appropriate *only* if Order No. 745 proceeds as lawful, and without prejudice to any position taken, or that may be taken, by any Participant(s) in the court proceeding(s) on Order No. 745, or in any related remand or subsequent Commission proceeding. This statement is offered solely by NEPOOL and not supported by the ISO.

VII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the market rule changes do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations.[70] Notwithstanding its request for waiver, the Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations:

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

- This transmittal letter;
- Blacklined Tariff sections reflecting the revisions submitted in this filing;
- Clean Tariff sections reflecting the revisions submitted in this filing;
- Testimony of Mr. Yoshimura (the "Yoshimura Testimony"), sponsored solely by the ISO; and

[69] The Participants Committee approved the main motion to support the Offer Flexibility Changes, with oppositions noted by: GDF SUEZ Energy Marketing NA, Inc., NextEra Energy Resources, LLC, and PPL EnergyPlus LLC; and abstentions noted by: Brookfield Energy Marketing Inc./Cross-Sound Cable Company, Calpine Energy Services, Consolidated Edison Energy, Inc., Dominion Energy Marketing, Inc, Dynegy Marketing and Trade, LLC, EquiPower Resources Management, LLC, Entergy Nuclear Power Marketing LLC, Essential Power, LLC, Exelon Generation Company, Granite Ridge, LIPA, Millennium Power Partners, PSEG Energy Resources & Trade LLC, Noble Americas Gas & Power Corp., and the Alternative Resource Sector's Small Renewable Generation Group Member.

[70] 18 C.F.R. § 35.13 (2012).

- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent.

35.13(b)(2) – As set forth in Section II above, the Filing Parties request that the revisions become effective on January 12, 2015.

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

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

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

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

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

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

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

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

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

VIII. CONCLUSION

As explained herein, integrating price-responsive demand into the existing Operating Reserves structure and Forward Reserve Market facilitates the objectives of allowing Market Participants to supply reserves to the market under common product definitions, take on comparable obligations for the market within which they participate, and receive the same price for the product they deliver. For these reasons and the reasons discussed in this transmittal letter, and as more fully explained in the supporting testimony, the PRD Reserves Changes are just and reasonable. Accordingly, the Filing Parties request that the Commission accept this filing with the revisions to become effective on January 12, 2015.

Respectfully submitted,

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I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

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

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

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

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

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

(k) words such as “hereunder,” “hereto,” “hereof” and “herein” and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to “include” or “including” means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

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

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

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

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

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

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

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

Allocated Assessment is a Covered Entity's right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

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

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

Alternative Technologies Regulation Pilot Program is the pilot described in Appendix J to Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

Asset Related Demand is a physical load that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of one or more individual end-use metered customers receiving service from the same point or points of electrical supply, with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration.

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

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

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

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

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

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

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

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

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

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

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

Average Hourly Load Reduction is either: (i) the sum of the Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (iv) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

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

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

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

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

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

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

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

Blackstart CIP O&M Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a

Blackstart Station's operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision of Blackstart Service.

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

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

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

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT, which also encompasses "System Restoration and Planning Service" under the predecessor version of Schedule 16.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

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

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

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

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

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Station-specific Rate CIP Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

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

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

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

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

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

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

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

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

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

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

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Clearing Price Floor is described in Section III.13.2.7.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

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

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

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible, equal to that Market Participant's Capacity Requirement (if any) adjusted to account for any relevant Capacity Load Obligation Bilaterals, as described in Section III.13.7.3.1 of Market Rule 1.

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

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

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

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

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

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

Capacity Requirement is described in Section III.13.7.3.1 of Market Rule 1.

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

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity-to-Service Ratio is defined in Section III.3.2.2(h) of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset.

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

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

Commercial Capacity, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.A of that policy.

Commission is the Federal Energy Regulatory Commission.

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

Common Costs are those costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Generating Capacity Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

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

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

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

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

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

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

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

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

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1 and purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

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

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

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

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

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

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

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

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

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

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

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

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

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

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

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

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

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

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

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

Demand Reduction Offer is an offer by a Market Participant with a Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

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

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

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

Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

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

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

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

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

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

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

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

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2. The demand reduction of a Demand Response Asset is the difference between the Demand Response Asset's actual demand measured at the Retail Delivery Point, which could reflect Net Supply, at the time the Demand Response Resource to which the asset is associated is dispatched by the ISO, and its adjusted Demand Response Baseline.

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

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

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

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

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

Demand Response Resource Notification Time is the minimum time, from the receipt of a Dispatch Instruction, that it takes a Demand Response Resource that was not previously reducing demand to start reducing demand.

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

Demand Response Resource Start-Up Time is the time required from the time a Demand Response Resource that was not previously reducing demand starts reducing demand in response to a Dispatch Instruction and the time the resource achieves its Minimum Reduction.

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

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

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

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

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

Desired Dispatch Point (DDP) is the Dispatch Rate expressed in megawatts.

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

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

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

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

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

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.13.1.4.6.1.

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions and must meet the technical requirements specified in the ISO New England Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources, however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

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

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

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

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

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

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

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at or below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.
Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

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

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

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

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

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

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

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

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

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a resource that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the resource's Supply Offer. This represents the highest MW output a Market Participant has offered for a resource for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit for all hours in which a resource has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

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

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the set of Supply Offer values that are used for NCPC calculation purposes as specified in Section III.F.1.a.

EFT is electronic funds transfer.

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.5 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

Elective Transmission Upgrade Applicant is defined in Section II.47.5 of the OATT.

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

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

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

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

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

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

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

Emergency Minimum Limit or Emergency Min means the minimum generation amount, in MWs, that a generating unit can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

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

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

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

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

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

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

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

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

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

Energy Offer Cap is $1,000/MWh.

Energy Offer Floor is negative $150/MWh.

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

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

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

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

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, the Capacity Requirement from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

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

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

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

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

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

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, and, subject to ISO evaluation, for the Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

Existing Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.1 of Market Rule 1.

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

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

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

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

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

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

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

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

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

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

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

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

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

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

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

Fast Start Generator means a generating unit that the ISO may dispatch within the hour through electronic dispatch and that meets the following criteria: (i) minimum run time does not exceed one hour; (ii) minimum down time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

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

FCA Payment is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual descending clock auction in the Forward Capacity Market, as described in Section III.13.2 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Forward Reserve Offer Cap is $14,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

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

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

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

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

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

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

FTR Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

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

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

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

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

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

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

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

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

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

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a generator that has been registered in accordance with the Asset Registration Process.

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

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

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

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

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

Governance Participant is defined in the Participants Agreement.

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

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

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

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

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

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

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

Hourly Adjusted Audited Demand Reduction is calculated in accordance with Section III.13.7.1.5.10.1.2.

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

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

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

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

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

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

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

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

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

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

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

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

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

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

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

Insufficient Competition is defined in Section III.13.2.8.2 of Market Rule 1.

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

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

Interconnection Agreement is the "Large Generator Interconnection Agreement" or the "Small Generator Interconnection Agreement" pursuant to Schedules 22 and 23 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 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures" or the "Small Generator Interconnection Procedures" pursuant to Schedules 22 and 23 of the ISO OATT.

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

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

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

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

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

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

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

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

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

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

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

Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

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

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

ISO means ISO New England Inc.

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

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

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

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

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

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

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

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

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

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

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

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

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

ITC Agreement is defined in Attachment M to the OATT.

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

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

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

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

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

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

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

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

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, or Real-Time Demand Response Event Hours to other hours and reduce the amount of capacity needed, while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, chilled water storage, and other forms of electricity storage.

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

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

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

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

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

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

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

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

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

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

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed

Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

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

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

Long Lead Time Generating Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

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

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

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

LSE means load serving entity.

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

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

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

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

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

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

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

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

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term “bulk power system costs to load system-wide” includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

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

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

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

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

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

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

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

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

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

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response

Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset's peak load less its uninterruptible load. For assets that deliver reductions through the use of generation, the Maximum Interruptible Capacity is the difference between the generator's maximum possible output and its expected output when not providing demand reduction. For assets that deliver demand reduction and Net Supply, the Maximum Interruptible Capacity is the asset's peak load plus Maximum Net Supply as measured at the Retail Delivery Point.

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

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

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

Measure Life is the estimated time a Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the Demand Reduction Value of the Demand Resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the Demand Reduction Value for an Existing Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1, which includes Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by a Demand Resource supplier as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by Demand Resource suppliers during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MUI is the market user interface.

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

MW is megawatt.

MWh is megawatt-hour.

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

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

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

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

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

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

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

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

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

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

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

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

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

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

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

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

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

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

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource, as described in Section III.13.2.3.2 of Market Rule 1.

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

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

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

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

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

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

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

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

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but does not have a winter audit value and a summer audit value.

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

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

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

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

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

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

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

NMPTC means Non-Market Participant Transmission Customer.

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

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

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

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

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

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.3.1.3.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

NPCC is the Northeast Power Coordinating Council.

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

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2017. Demand Response Resources for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

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

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

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

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

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

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

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

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

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

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

Operations Date is February 1, 2005.

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

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

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service

Administration Agreement covers the rights and responsibilities for the administration of transmission service.

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

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

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

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

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

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

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

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

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

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

Peak Energy Rent (PER) is described in Section III.13.7.2.7.1 of Market Rule 1.

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

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Posturing Credits are the Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

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

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

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

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

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

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

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

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

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

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

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

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

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

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

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

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

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

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

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

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

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

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

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

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

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

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

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Price Response Program is the program described in Appendix E to Market Rule 1.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

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

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

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

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

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 Capability (REGCAP) means the amount of Regulation capability available on a Market Participant's Resource as calculated by the ISO based upon that Resource's Automatic Response Rate and the available regulating range as specified in ISO New England Manual 11 – Market Operations.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.

Regulation Rank Price is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

Regulation Requirement is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

Regulation Service Credit is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

Regulation Service Megawatts are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, for Capacity Commitment Periods commencing on or after June 1, 2017, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2017, a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New

England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

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

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

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

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

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

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to: (i) a Generator Asset's Economic Minimum Limit; (ii) a Dispatchable Asset Related Demand's Minimum Consumption Limit; or (iii) for Regulation purposes with respect to a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

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

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

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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

Start-Up Fee is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

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

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

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

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

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

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

Supplemented Capacity Resource is described in Section III.13.5.3.2 of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

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

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, or Schedule 23 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of (1) a generating Resource that can be converted fully into energy within ten minutes from the request of the ISO(2) a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO.

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

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

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

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

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Time-on-Regulation Credit is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

Time-on-Regulation Megawatts is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

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

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

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

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

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

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

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule

20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

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

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

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

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

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

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

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

III.1.2 [Reserved.]

III.1.3 Definitions.

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

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

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 Requirements for Certain Transactions.

III.1.4.1 ISO Settlement of Certain Transactions.

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

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

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

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

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

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

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

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

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

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

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

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

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

(c) As further requirements:

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

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

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

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

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

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

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

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

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

(d) The Claimed Capability Audit value for steam turbine assets with 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) The time and date of an Establish Claimed Capability Audit shall be unannounced.

(b) For a newly commercial Generator Asset:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2

III.1.5.1.3. Seasonal Claimed Capability Audits.

(a) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:

(i) Non-intermittent daily hydro; and

(ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

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

(c) Except as provided in Section III.1.5.1.3(m) below, a summer Seasonal Claimed Capability Audit must be conducted:

(i) At least once every Capability Demonstration Year;

(ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.

(d) A winter Seasonal Claimed Capability Audit must be conducted:

(i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:

(1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.

(2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.

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

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

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

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

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

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

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

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

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

(j) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal

Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:

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

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

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

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

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

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

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

(l) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

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

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

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

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

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

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

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

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

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

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

(ii) An ISO-Initiated Claimed Capability Audit value shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.

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

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

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

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

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

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

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

Duration Required for an ISO-Initiated Claimed Capability Audit	
Unit Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2

III.1.5.2 ISO-Initiated Parameter Auditing.

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

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

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

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

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

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

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

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

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

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

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

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

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

(iii) **Demand Response Resource Start-Up Time**. The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered

Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

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

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

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

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

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

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

(e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Assetor 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.

(iii) Market Participants will be compensated for audits of dual fuel capability conducted under this Section III.1.5.2 pursuant to Appendix F. If a Market Participant has a Generator Asset that cleared in the Day-Ahead Energy Market and the Market Participant is audited for all or part of the Generator Asset’s Day-Ahead schedule on a fuel other than the fuel that formed the basis of the Generator Asset's Supply Offer in the Day-Ahead Energy Market, and Appendix F would otherwise not compensate the Generator Asset on the higher-priced fuel, then the Market Participant will receive additional compensation equal to the difference between 1) the audit costs based on the cost-based Reference Levels calculated using the fuel on which the audit was performed and 2) amounts calculated for that same operation as reflected in the greater of the Day-Ahead Supply Offer and the cost-based Reference Levels calculated using the fuel on which the Day-Ahead Supply Offer was based. Compensation pursuant to this Section III.1.5.2(e)(iii) shall be charged in accordance with Section III.F.3.2.19 of Appendix F.

(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.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

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

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

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

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

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

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

III.1.7.4 [Reserved.]

III.1.7.5 [Reserved.]

III.1.7.6 Scheduling and Dispatching.

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

Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch.

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

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

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

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

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

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

III.1.7.7 Energy Pricing.

The price paid for energy, including demand reductions, bought and sold in the New England Markets will reflect the hourly Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices in an hour caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices in an hour, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

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

III.1.7.9 Real-Time Reserve Prices.

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

III.1.7.10 Other Transactions.

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

(b) [Reserved.]

(c) [Reserved.]

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

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

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

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

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

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

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

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

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

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

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

III.1.7.12 [Reserved.]

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

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

III.1.7.18 Regulation.

(a) Regulation shall be supplied from generators located within the metered electrical boundaries of the New England Control Area. Market Participants offering Regulation shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall obtain and maintain an amount of Regulation equal to the New England Control Area Regulation objective as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) The Regulation range of a unit shall be at least twice the amount of Regulation assigned and no less than the minimum specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(d) A unit that is providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided. The amount of Regulation provided by a unit shall serve to redefine the Economic Minimum Limit and Economic Maximum Limit of that unit, in that the amount of Regulation shall be added to the unit's Economic Minimum Limit or automatic low limit while regulating, whichever is greater, and subtracted from its Economic Maximum Limit or automatic high limit, which ever is less. Qualified Regulation must satisfy the verification tests described in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19 Ramping.

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

III.1.7.19A Real-Time Reserve.

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

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

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

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

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

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

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

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

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

III.1.8 [Reserved.]

III.1.9 Pre-scheduling.

III.1.9.1 [Reserved.]

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each generating unit as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline specified in the ISO New England Manuals and ISO New England Administrative Procedures and shall remain in effect without change throughout each such period for which a specification was submitted. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

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

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

(c) In the Real-Time Energy Market,

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

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

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

Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

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

III.1.10.1A Day-Ahead Energy Market Scheduling.

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

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

(b) [Reserved.]

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

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

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

(iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to $0.0/MWh; and

(iv) If the sum of all submitted fixed External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all fixed External Transaction sales at the applicable External Node shall be set equal to $1,000/MWh.

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

(d) Market Participants selling into the New England Markets, from either internal Resources or External Resources, shall submit Supply Offers or External Transactions for the supply of energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Regulation, Operating Reserve or other services as applicable, for the following Operating Day. Supply Offers shall be submitted to the ISO in the form specified by the ISO and shall contain the information specified in the ISO's Offer Data specification, as applicable. External Transactions shall be submitted to the ISO according to Section III.1.10.7 of this Market Rule 1. The ISO shall not consider Start-Up Fees, No-Load Fee, notification times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

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

(i) Shall specify the Resource and energy for each hour in the offer period;

(ii) Shall specify the amounts and prices for the entire Operating Day for each Resource offered by the Market Participant to the ISO;

(iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify Start-Up Fees and No-Load Fee equal to the specification of such fees for such unit on file with the ISO (Market Participant changes to the Start-Up Fee and No-Load Fee can only occur during the open periodic bidding enrollment periods (daily));

(iv) Shall set forth any special conditions upon which the Market Participant proposes to supply a Resource increment;

(v) Shall specify a minimum run time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;

(vi) Shall constitute an offer to submit the generating Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Economic Minimum Limit may be revised to reflect the Self-Scheduled output level of the Resource and for a Limited Energy

Resource, the Economic Maximum Limit may be revised to reflect maximum energy available for the Operating Day, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;

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

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

(ix) Shall not specify an energy offer or bid price below $0/MWh or above $1,000/MWh.

(e) A Market Participant that wishes to make a Resource available to sell Regulation service shall submit a Supply Offer for Regulation that shall specify the Automatic Response Rate in megawatts per minute, the price in dollars per MWh of the Regulation capability being offered, such Regulation capability as calculated by the ISO by multiplying the submitted Automatic Response Rate by five minutes, and such other information specified by the ISO as may be necessary to evaluate the Supply Offer and the generating Resource's Regulation Opportunity Costs. The price of the Supply Offer shall not exceed $100/MWh. Qualified Regulation capability must satisfy the verification tests specified in the ISO New England Manuals and ISO New England Administrative Procedures. Regulation capability amounts will be adjusted as necessary in the case where a generating unit's compliance rating is less than 90%. The audited Regulation capability will be deemed equal to the most recently calculated compliance rating times the 5-minute Regulation capability quantities utilized in that compliance rating calculation, rounded to the nearest whole megawatt. The Resource's Automatic Response Rate will then be adjusted based upon the audited Regulation capability.

(f) [Reserved.]

(g) Each Supply Offer or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Resource and an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days.

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

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

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

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

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers or Demand Reduction Offers to sell energy in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as generators or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

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

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

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

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

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

III.1.10.3 Self-Scheduled Resources.

Self-Scheduled Resources shall be governed by the following principles and procedures.

(a) [Reserved.]

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

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

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

III.1.10.4 [Reserved.]

III.1.10.5 External Resources.

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

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

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

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

III.1.10.6 Dispatchable Asset Related Demand Resources.

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

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

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

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

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

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

(f) abide by the ISO maintenance coordination procedures;

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

(h) comply with the ISO New England Manuals.

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

III.1.10.7 External Transactions.

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

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

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

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

(e) All Real-Time External Transactions shall be scheduled and curtailed in accordance with the ISO New England Manuals and all applicable tariffs.

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

(i) Capacity Export Through Import Constrained Zone Transactions:

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

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

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

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

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

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

(ii) FCA Cleared Export Transactions:

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

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

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

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

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

(iii) Same Reserve Zone Export Transactions:

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

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

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

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

(iv) Unconstrained Export Transactions:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

III.1.10.8 ISO Responsibilities.

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

Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

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

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

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

III.1.10.9 Hourly Scheduling.

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

(b) A Market Participant may adjust the schedule of a Resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the ISO is notified not later than 20 minutes prior to the hour, as follows:

(i) A Market Participant may Self-Schedule any of its Resources consistent with the ISO New England Manuals and ISO New England Administrative Procedures;

(ii) [Reserved]; or

(iii) [Reserved]; or

(iv) A Market Participant may remove from service a Resource increment previously designated as Self-Scheduled consistent with the ISO New England Manuals and ISO New England Administrative Procedures.

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

(d) **[Reserved.]**

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

III.1.11 Dispatch.

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

III.1.11.1 Resource Output and Demand Reduction.

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

III.1.11.2 Operating Basis.

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

III.1.11.3 Pool-dispatched Resources.

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

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

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

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

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

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

III.1.11.4 Emergency Condition.

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

III.1.11.5 Regulation.

(a) A Market Participant may satisfy its Regulation obligation from its own Resources capable of performing Regulation service or by purchases from the ISO through the New England Markets at the rates set forth in Section III.3.2.2.

(b) The ISO shall obtain Regulation service from the least-cost alternatives available from either Pool-Scheduled Resources or Self-Scheduled Resources as needed to meet New England Control Area requirements not otherwise satisfied by the Market Participants. The ISO assigns Regulation to eligible generating units using the ISO Regulation assessment software. The Regulation assessment software calculates, at five minutes after the hour and on demand as needed, the optimal set of generating units required to meet the Regulation Requirement. The software first calculates a Regulation Rank Price, based on estimates of Time-on-Regulation Credits, Regulation Service Credits, estimated Regulation Opportunity Costs, Regulation Capability and other factors, as specified below, that consider the impact of Regulation assignment on the Real-Time Energy Market. An interim clearing price is then calculated and the Regulation Rank Prices are updated using this interim clearing price to recognize that actual payments for Regulation are based upon the Regulation Clearing Price and not the Regulation offer price. The software continues to iterate in this manner until convergence is reached, resulting in an optimal selection of generating units for Regulation assignment. The ISO utilizes the output from this software when evaluating the set of generating units for Regulation assignment. In the event that one or more generating units to be selected have equal Regulation Rank Prices, the ISO shall select the generating unit for Regulation assignment with the largest Regulation Capability. Details of the process and calculations are described below.

(1) At the start of each operating hour, the ISO calculates an initial Regulation Rank Price for each eligible unit offering to provide Regulation using the ISO's Regulation assignment software. The initial Regulation Rank Price for each unit is equal to the sum of the following calculations divided by that unit's Regulation Capability:

(a) Time-on-Regulation Credit estimate calculated as the product of the Regulation Capability times the Regulation offer price;

(b) Regulation Service Credit estimate is set equal to the Time-on-Regulation Credit estimate to meet the 50/50 revenue mix objective as determined by the ISO in accordance with procedures specified in the ISO New England Manuals and ISO New England Administrative Procedures;

(c) Regulation Opportunity Cost estimate calculated as the product of the opportunity cost MW times the opportunity cost price differential where:

(i) Opportunity cost MW is calculated as the absolute value of the difference between the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by Economic Max and Economic Min, and EstRegGen.

(ii) EstRegGen is the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by RSETHI and RSETLO. RSETHI is equal to the Regulation High Limit – Regulation Capability. RSETLO is equal to the Regulation Low Limit + Regulation Capability.

(iii) To more accurately estimate the actual Regulation Opportunity Cost, EstRegGen is further constrained as follows to account for units with large regulating ranges and slow response rates: if actual generation is less than EstRegGen and EstRegGen is greater than RSETLO, then EstRegGen is constrained up by the greater of (actual output + (SlowWideTime * Automatic Response Rate)) and RSETLO; if actual generation is greater than EstRegGen and EstRegGen is less than RSETHI, then EstRegGen is constrained down by the lesser of (actual output – (SlowWideTime * Automatic Response Rate)) and RSETHI. The SlowWideTime is determined by the ISO based upon empirical studies. The initial SlowWideTime value, and subsequent updates, shall be posted on the ISO's website.

(iv) Opportunity cost price differential is calculated as the absolute value of the difference between the average offer price of the opportunity MW and the Real-Time nodal LMP of the unit.

(d) Lookahead penalty estimate. The lookahead calculation assigns a cost penalty to units in the selection process if there is a change in energy offer prices near EstRegGen. It is calculated as 0.17 multiplied by the greater of:

(i) the unit's energy offer price at a higher output level (LookupRegGen as defined below) minus its energy offer price at EstRegGen, multiplied by (LookupRegGen – EstRegGen); and

(ii) the unit's energy offer price at EstRegGen minus its energy offer price at a lower output level (LookdownRegGen as defined below), multiplied by (EstRegGen -LookdownRegGen), where, LookupRegGen = (EstRegGen + (LookAheadMinutesUp * Automatic Response Rate)) as bounded by Regulation High Limit; and LookdownRegGen = (EstRegGen – (LookAheadMinutesDown * Automatic Response Rate) as bounded by Regulation Low Limit), And where the initial values of LookAheadMinutesUp and LookAheadMinutesDown, and subsequent updates, will be posted on the ISO's website.

(e) A tiebreaker adder is calculated for both pool-scheduled and Self-Scheduled Regulation units. The tiebreaker adder is equal to a tiebreaker multiplier (.000001) times the difference between a tiebreaker megawatt reference value (500 MW) and the Regulation Capability of the unit.

For Self-Scheduled Regulation, all values calculated under this Section III.1.11.5(b)(1) are set equal to zero except for the tiebreaker adder.

(2) The ISO's Regulation assignment software creates an initial merit order stack of eligible Regulation Capability by sorting the generating units by the initial Regulation Rank Prices calculated under Section III.1.11.5 (b)(1) in ascending order. Generating units are then selected in rank order until the Regulation Requirement is met. An initial clearing price is then calculated based upon the highest Regulation offer price associated with the initial set of generating units selected to meet the Regulation Requirement. Updated Regulation Rank Prices are then recalculated for generating units with Regulation offer prices that are less than the initial clearing price by substituting the initial clearing price for the generating unit's Regulation offer price, recalculating the Time-On-Regulation Credit and the Regulation Service Credit estimates; adding the originally calculated values under Sections III.1.11.5(b)(1)(c), (d) and (e) to these recalculated values and dividing this total by the unit's Regulation Capability. These updated Regulation Rank Prices are utilized along with the initial Regulation offer prices adjusted to include opportunity costs that are greater than or equal to the initial clearing price to create an updated generating unit list sorted by ascending Regulation Rank Prices. An updated clearing price is then calculated and the software continues to iterate in this manner until convergence is reached producing an optimal generating unit rank order list for use in assigning Regulation.

(3) Shortly after the start of an hour and during the hour as needed, the ISO updates the generating unit rank order list using the ISO's Regulation assignment software based on any

changes to Regulation Capability eligibility and other current information, including any changes to Self-Schedule Regulation. The ISO uses this updated Regulation rank order list to assign Regulation for the upcoming hour and to make changes to Regulation assignments within the hour.

(c) The ISO shall dispatch Resources for Regulation by sending Regulation signals and instructions to Resources from which Market Participants, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, have offered Regulation service. Market Participants shall comply with Regulation dispatch signals and instructions transmitted by the ISO and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources supplying load in the New England Control Area as close to desired output levels as practical, consistent with Good Utility Practice.

III.1.11.6 [Reserved]

III.1.12 Dynamic Scheduling.

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

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

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

(c) An entity requesting dynamic scheduling shall be responsible for arranging for the provision of signal processing and communication from the generating unit and other participating Control Area and complying with any other procedures established by the ISO regarding dynamic scheduling as set forth in the ISO New England Manuals. Allocation of costs associated with dynamic scheduling shall be determined and filed with the Commission following the first request.

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

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

III.2.1 Introduction.

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

III.2.2 General.

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

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

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of generation supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area, transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.4, every offer of energy by a Market Participant from a generating Resource, Demand Response Resource, an External Transaction purchase Resource and a Dispatchable Asset Related Demand Resource that is following economic dispatch instructions of the ISO will be utilized in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

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

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and locational Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the most recent power flow solution produced by the State Estimator, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Determination of Energy Offers Used in Calculating Real-Time Prices and Real-Time Reserve Clearing Prices.

(a) During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market.

(b) To determine the energy offers submitted to the New England Markets that shall be used during the Operating Day to calculate the Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall determine which generating Resources, Demand Response Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources are following its economic dispatch instructions. A generating Resource, Demand Response Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-Time Prices if:

(i) the applicable Supply Offer or Demand Reduction Offer price submitted by a Market Participant for energy from the generating Resource, Demand Response Resource or External Transaction purchase is less than or equal to the Dispatch Rate associated with that Resource or External Transaction purchase;

(ii) the applicable Demand Bid price submitted by a Market Participant for energy from the Dispatchable Asset Related Demand Resource is greater than or equal to the Dispatch Rate associated with that Dispatchable Asset Related Demand Resource;

(iii) the generating Resource, other than a Fast Start Generator, is operating at or above its Economic Minimum Limit;

(iv) the Fast Start Generator is operating at or above its Economic Minimum Limit and the applicable Supply Offer price submitted by a Market Participant for energy from the Fast Start Generator is less than or equal to the Dispatch Rate associated with that Fast Start Generator;

(v) The Demand Response Resource, other than a Fast Start Demand Response Resource, is operating at or above its Minimum Reduction;

(vi) The Fast Start Demand Response Resource is operating at or above its Minimum Reduction and the applicable Demand Reduction Offer price submitted by a Market Participant for energy from the Resource is less than or equal to the Dispatch Rate associated with the Resource; and

(vii) the generating Resource, Demand Response Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource is specifically requested to operate or reduce consumption by the ISO's dispatcher and the associated energy offers or bids submitted are otherwise eligible to be included in the calculation of Real-Time Locational Marginal Prices.

(c) In determining whether a generating Resource or External Transaction purchase satisfies the condition described in Section III.2.4(b), the ISO will determine the Supply Offer price associated with an energy offer by comparing the actual megawatt output of the generating unit or External Transaction purchase with the Market Participant's Supply Offer price curve for that generating unit or External Transaction purchase. Because of practical generator response limitations, a generating unit whose megawatt output is not more than ten percent above or below the megawatt level specified in the Supply Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

(d) In determining whether a Dispatchable Asset Related Demand Resource satisfies the condition described in Section III.2.4(b), the ISO will determine the Demand Bid price associated with a Demand Bid by comparing the actual megawatt consumption of the Dispatchable Asset Related Demand Resource with the Market Participant's Demand Bid price curve for that Dispatchable Asset Related Demand Resource. Because of practical Dispatchable Asset Related Demand Resource response limitations, a Dispatchable Asset Related Demand Resource whose megawatt consumption is greater than or equal to ninety percent, and less than or equal to 110% of the megawatt level specified in the Demand Bid price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy demand bid price used in the calculation of Real-Time Prices shall not be lower than the applicable Dispatch Rate.

(e) In determining whether a Demand Response Resource satisfies the condition described in Section III.2.4(b), the ISO will compare the actual megawatt demand reduction of the Demand Response Resource with the Market Participant's Demand Reduction Offer price curve for that Resource. Because of practical response limitations, a Demand Response Resource whose megawatt demand reduction is not more than ten percent above or below the megawatt level specified in the Demand Reduction Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

III.2.5 Calculation of Real-Time Nodal Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, Demand Response Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.8; and (5) the effect on transmission losses caused by the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of

Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node.

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

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

III.2.6 Calculation of Day-Ahead Nodal Prices.

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

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

The process for clearing External Nodes differs from the process for clearing other Nodes in that, in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(a) The ISO shall determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of Real-Time Nodal Prices specified under Section III.2.5, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMSNR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

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

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

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

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

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

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

III.2.8 Hubs and Hub Prices.

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

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

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

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

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

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

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

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

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

Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area; provided that Section III.E2.9 sets forth the Day-Ahead Energy Market and Real-Time Energy Market settlement rules for Demand Response Resources.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

(a) For each Market Participant for each hour, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows:

(i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each hour a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.

(ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each hour a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its generation Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.

(iii) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each hour a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.

(iv) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each hour a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation at that Location

(b) For each Market Participant for each hour, the ISO will determine a Real-Time Energy Market position. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each hour a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each hour a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by generating Resources, External Resources, and External Transaction purchases at that Location.

(iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each hour a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange** – Each Market Participant shall have for each hour a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation –** Each Market Participant shall have for each hour a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue.

(c) For each Market Participant for each hour, the ISO will determine the difference between the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)) and the Real-

Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each hour a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each hour a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each hour a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each hour a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between the Real-Time Locational Adjusted Net Interchange and the Day-Ahead Locational Adjusted Net Interchange.

(d) For each Market Participant for each hour, the ISO will determine Day-Ahead Energy Market monetary positions representing a charge or credit for its net purchases from or sales to the ISO Day-Ahead Energy Market. The Day-Ahead Energy Market Energy Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Energy Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

(e) For each Market Participant for each hour, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market. The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that hour multiplied by the Energy Component of the Real-Time Locational Marginal Prices for that hour. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that hour multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices for that hour.

The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that hour multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices for that hour.

(f) For each hour, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Congestion Charge/Credits.

(g) For each hour, the ISO will determine the excess or deficiency in loss revenue associated with the Day-Ahead Energy Market. The Day-Ahead Loss Revenue shall be equal to the sum of all Market Participants' Day-Ahead Energy Market Energy Charge/Credits and Day-Ahead Energy Market Loss Charge/Credits.

(h) For each hour for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(g)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(i) For each hour, the ISO will determine the excess or deficiency in loss revenue associated with the Real-Time Energy Market. The Real-Time Loss Revenue shall be equal to the sum of all Market

Participants' Real-Time Energy Market Deviation Energy Charge/Credit and Real-Time Energy Market Deviation Loss Charge/Credit plus Non-Market Participant Transmission Customer loss costs. The ISO will then adjust Real-Time Loss Revenue to account for Inadvertent Energy Revenue, as calculated under Section III.3.2.1(k) and Emergency transactions as described under Section III.4.3(a).

(j) Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each hour multiplied by the difference between the Loss Component of the hourly Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the hourly Real-Time Price at the source point or New England Control Area boundary source interface.

(k) For each hour, the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at each External Node by the associated Real-Time Locational Marginal Price and then summing these values for all External Nodes.

(l) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(k)). The Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations and Real-Time Generation Obligations over all Locations, measured as absolute values.

(m) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Real-Time Loss Revenue (Section III.3.2.1(i)). The Real-Time Loss Revenue Charges or Credits shall be equal to the Real-Time Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

III.3.2.2 Regulation.

(a) Each Market Participant shall have an hourly Regulation obligation equal to its pro rata share of the New England Control Area Regulation requirements for the hour, based on the Market Participant's total Real-Time Load Obligation in the New England Control Area for the hour. A Market Participant that does not meet its hourly Regulation obligation through its own Resources shall be charged for Regulation dispatched by the ISO to meet such obligation at the Regulation Clearing Price determined in accordance with paragraph (e) of this Section, plus the amounts, if any, described in paragraph (d) and (k) of this Section.

(b) A Market Participant supplying Regulation at the direction of the ISO in excess of its hourly Regulation obligation shall be credited for Time-On-Regulation Megawatts at the higher of (i) the Regulation Clearing Price.

(c) A Market Participant supplying Regulation at the direction of the ISO shall receive a credit for Regulation Service Megawatts at the Regulation Clearing Price multiplied by the Capacity-to-Service Ratio. The Capacity-to-Service Ratio is described under Subsection (h).

(d) Each Market Participant shall be charged its pro rata share of the total Regulation Service Credits for the hour, based upon the Market Participant's total Real-Time Load Obligation in the New England Control Area for the hour.

(e) The Regulation Clearing Price shall be determined by the ISO. The Regulation Clearing Price for each hour shall be equal to the time weighted average of all interval-based Regulation Clearing Prices calculated within the hour. The Regulation Clearing Price for each interval within the hour shall be equal to the highest Regulation Supply Offer price inclusive of the Regulation Opportunity Cost as calculated under III.3.2.2(i) of any generating Resources selected to provide Regulation in that interval. Regulation Clearing Prices shall be posted and finalized by the ISO in accordance with Seciton III.2.9A of this Market Rule 1.

(f) A Market Participant's Regulation Service Megawatts shall be determined by the ISO. A Market Participant's hourly Regulation Service Megawatts for each generating Resource providing Regulation shall be equal to the sum of the absolute value of the generation movement, in megawatts, towards the Regulation set point, such movement calculated in four second intervals based upon the generating Resource's Automatic Response Rate.

(g) A Market Particpant's Time-on-Regulation Megawatts shall be determined by the ISO. A Market Participant's hourly Time-on-Regulation Megawatts for each generating Resource providing Regulation shall be equal to the Regulation capability provided multiplied by the minutes of Regulation provision in the hour, divided by sixty.

(h) The Capacty-to-Service Ratio shall be determined by the ISO. The Capacity-to-Service Ratio is the relationship between Regulation capability provided and Regulation Service Megawatts provided in an hour. Based on historical analysis, on average, one megawatt of Regulation capability will produce ten megawatts of Regulation Service Megawatts. Based on this relationship, the Capacity-to-Service Ratio shall initially be set equal to 0.1 such that the revenue associated with Time-on-Regulation Megawatts and Regulation Service Megawatts associated with a Resource providing Regulation shall be equally split. The revenue split assumption and the Capacity-to-Service Ration may be changed from time-to-time and such changes shall be filed with the Commission for approval.

(i) In determining the credit to a Market Participant that is selected to provide Regulation and that actively follows the ISO's Regulation signals and instructions, the unit specific Regulation Opportunity Cost of a generating Resource shall be determined for each hour that the ISO requires a generating Resource to provide Regulation and shall be equal to the product of (i) the deviation of the generating Resource's output necessary to follow the ISO's Regulation signals from the generating Resource's expected output level if it had been dispatched in economic merit order and (ii) the absolute value of the difference between the Real-Time Price at the generation Node for the generating Resource and the megawatt weighted average Supply Offer price for the energy associated with the deviation of the generating Resource's expected output level if it had been dispatched in economic merit order.

(j) If revenues from the Regulation Clearing Price are insufficient to cover a Market Participant's actual costs for providing Regulation during the hour, a make-whole payment is calculated at the end of each hour equal to the greater of zero and the Market Participant's actual cost of providing Regulation minus the Regulation Clearing Price revenues.

(k) Amounts credited for Regulation make-whole payments, as calculated in Section III.3.2.2(j), in an hour shall be allocated and charged to each Market Partcipant that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in MWh during that hour.

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(f) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) Hourly net costs in excess of Real-Time Prices attributable to the purchase of Emergency energy by the ISO from other Control Areas shall be allocated to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for Pool-Scheduled Resources not following ISO dispatch instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following ISO dispatch instructions and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generating Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations.

(b) Hourly net revenues in excess of Real-Time Prices attributable to the sale of Emergency energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for Pool-Scheduled Resources following ISO dispatch instructions and Self-Scheduled generating Resources with dispatchable increments above their Self-Scheduled amounts following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generating Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load or in such other manner as may be described in ISO New England Manual M-28 (Market Rule 1 Accounting). Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6 and Section III.E2, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

Non-Market Participant Transmission Customers shall be charged or credited for Congestion Costs as specified in Section III.1 of this Market Rule 1.

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time

Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 Eligible Data.

The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily Coincident Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

For revisions to meter data associated with assets that connect the New England Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the New England Control Area and the other Control Area to maintain an accurate record of inadvertent energy flow.

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

(b) Errors on the part of the ISO in the administration of Market Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the Correction Limit.

III.3.7 Eligibility for Billing Adjustments.

(a) Errors in Market Participant’s statements resulting from errors in settlement software, errors in data entry by ISO personnel, and settlement production problems, that do not affect the day-ahead schedule or real-time system dispatch, will be corrected as promptly as practicable. If errors are identified prior to the issuance of final statements, the market will be resettled based on the corrected information.

(b) Calculations made by scheduling or dispatch software, operational decisions involving ISO discretion which affect scheduling or real-time operation, and the ISO's execution of mandatory dispatch directions, such as self-schedules or external contract conditions, are not subject to retroactive correction and resettlement. The ISO will settle and bill the Day-Ahead Energy Market as actually scheduled and the Real-Time Energy Market as actually dispatched. Any post-settlement issues raised concerning operating decisions related to these markets will be corrected through revision of operations procedures and guidelines on a prospective basis.

(c) While errors in reporting hourly metered data may be corrected (pursuant to Section III.3.8), Market Participants have the responsibility to ensure the correctness of all data they submit to the market settlement system.

(d) Disputes between Market Participants regarding settlement of internal bilateral transactions shall not be subject to adjustment by the ISO, but shall be resolved directly by the Market Participants unless they involve an error by the ISO that is subject to resolution under Section III.3.7(a).

(e) Billing disputes between Market Participants and the ISO or Non-Market Participants and the ISO shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

(f) Criteria for Meter Data Errors to be eligible for a Requested Billing Adjustment. In order to be eligible to submit a Requested Billing Adjustment due to a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process, a Market Participant must satisfy one of the following two conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than thirty-six (36) days prior to the Correction Limit for Directly Metered Assets and no later than two (2) days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; or (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader and reported to the ISO by the Meter Data Error RBA Submission Limit, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per Asset over a calendar month. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website.

(b) Within three Business Days of the receipt by the ISO's Chief Financial Officer of an RBA form for a Meter Data Error, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Meter Data Error correction ("Notice of Meter Data Error Correction"), including, subject to the provisions of the ISO New England Information Policy, the specific details of the correction and the identity of the affected metering domains and the affected Host Participant Assigned Meter Readers. The "Notice of Meter Data Error Correction" shall identify a specific representative of the ISO to whom all communications regarding the matter are to be sent.

(c) In order for a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process to be eligible for correction, the Meter Data Error must satisfy one of the following conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than 36 days prior to the Correction Limit for Directly Metered Assets and no later than two days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per asset over a calendar month; and (3) if the Meter Data Error involves only Coincident Peak Contribution values, the average of the daily Meter Data Errors involving Coincident Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

(d) For a Meter Data Error, the Host Participant Assigned Meter Reader must submit to the ISO corrected meter data for Directly Metered Assets prior to the 46th calendar day after the Meter Data Error RBA Submission Limit. Corrected metered data for Profiled Load Assets and Coincident Peak Contribution values, must be submitted to the ISO by the Host Participant Assigned Meter Reader prior to the 87th calendar day after the Meter Data Error RBA Submission Limit. Corrected internal bilateral transactions data must be submitted to the ISO by a Market Participant prior to the 91st calendar day after the Meter Data Error RBA Submission Limit.

Any corrected data received after the specified deadlines is not eligible for use in the settlement process.

The Host Participant Assigned Meter Reader or Market Participant, as applicable, must confirm as part of its submission of corrected data that the eligibility criteria described in Section III.3.8(c) of Market Rule 1 have been satisfied.

To the extent that the correction of a Meter Data Error is for a Directly Metered Asset that affects multiple metering domains, all affected Host Participant Assigned Meter Readers or Assigned Meter Readers must notify the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit that the corrected Directly Metered Asset data is acceptable to them in order for the ISO to use the corrected data in the final settlement calculations. The Host Participant Assigned Meter Reader for the Directly Metered Asset is responsible for initiating an e-mail to every affected Host Participant Assigned Meter Reader or Assigned Meter Reader in order to obtain such acceptance and shall coordinate delivery of such acceptance to the ISO. The Host Participant Assigned Meter Reader for the Directly Metered Asset is also responsible for submitting all corrected and agreed upon Directly Metered Asset data to the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit.

(e) After the submission of corrected meter and internal bilateral transactions data, the ISO will have a minimum of 30 calendar days to administer the final settlement based on that data. Revised data will be used to recalculate all charges and credits, except that revised data will not be used to recalculate the PER adjustment, including the Hourly PER and Monthly PER values. Revised data will also not be used to recalculate Demand Resource Seasonal Peak Hours. The results of the final settlement will then be included in the next Invoice containing Non-Hourly Charges and the ISO will provide to the Chair of the NEPOOL Budget and Finance Subcommittee written notification that the final settlement has been administered.

III.8A Demand Response Baselines

Section III8.A shall govern Demand Response Baselines calculated for Capacity Commitment Periods commencing prior to June 1, 2017.

A Demand Response Baseline is calculated for any Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that requires a baseline on a daily basis using five-minute meter data.

8A.1 Establishing the Initial Demand Response Baseline

The Demand Response Baseline for a new Real-Time Demand Response Asset or Real-Time Emergency Generation Asset (an asset with no previously computed Demand Response Baseline) shall be the simple average of meter data for the asset for each five-minute interval from the initial ten non-Demand Response Holiday weekdays. The initial ten non-Demand Response Holiday weekdays of meter data used to establish the Demand Response Baseline shall consist of the first ten consecutive non-Demand Response Holiday weekdays with a complete set of interval meter data. A Market Participant may not submit Demand Reduction Offers until the month following the initial establishment of a Demand Response Baseline for an asset.

If two or more existing Real-Time Demand Response Assets (assets registered with the ISO with previously computed Demand Response Baselines) located at or behind the same retail delivery point are consolidated into one Real-Time Demand Response Asset located at the retail delivery point, or a significant change in load, generation, or reported meter data at an existing Real-Time Demand Response Asset or Real-Time Emergency Generation Asset occurs, a new initial Demand Response Baseline must be established for the asset.

8A.2 Establishing the Demand Response Baseline for the Next Day

If, for a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

(a) the asset has been dispatched or audited in the present day pursuant to Section III.13, or;
(b) the Demand Reduction Offer associated with the asset is eligible in the present Operating Day for payments pursuant to Section III.E1.9, or;
(c) the present day is a Demand Response Holiday, Saturday or Sunday, then:

the asset's Demand Response Baseline, in each five-minute interval, for the next day is equal to the Demand Response Baseline, in the same five-minute interval from the present day.

8A.3 Determining if Meter Data From the Present Day is Used in the Demand Response Baseline for the Next Day

If, for a Real-time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

(a) the present day is not a Demand Response Holiday, Saturday or Sunday, and; the asset has not been dispatched or audited in the present day pursuant to Section III.13, and; the Demand Reduction Offer associated with the asset is not eligible in any hour of the present day for payments pursuant to Section III.E1.9, or;

(b) the present day is not a Demand Response Holiday, Saturday or Sunday and more than seven of the prior 10 non-Demand Response Holiday weekdays have established a Demand Response Baseline determined pursuant to Section III.8A.2; then:

the asset's Demand Response Baseline in each five-minute interval, for the next day is calculated as the sum of 0.9 times the asset's Demand Response Baseline established for the present day in the same five-minute interval and 0.1 times the asset's meter data in the same five-minute interval from the present day.

8A.4 Baseline Adjustment

8A.4.1 Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets Without Generation or From Real-Time Emergency Generation Assets Without Additional Generation

For each day the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between the asset's actual metered demand and its Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response

Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load.

8A.4.2 Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets with Generation or From Real-Time Emergency Generation Assets With Additional Generation

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between the sum of the asset's actual metered demand and the output of all generators, or for Real-Time Emergency Generation Assets all additional generators, located behind the asset's end-use customer meter in the same time intervals and the asset's Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Facility Load.

8A.4.3 Baseline Adjustment for Real-Time Demand Reductions Produced By Directly Metered Generation

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset that is comprised of a Distributed Generation asset located behind the end-use customer meter of an individual end-use customer facility, the asset's Demand Response Baseline shall not be subject to the baseline adjustment.

8A.4.4 Baseline Adjustment for Real-Time Demand Reductions Produced by a Real-Time Demand Response Asset Located At a Retail Delivery Point Where There Are No Other Real-Time Demand Response Assets At or Behind that Retail Delivery Point

For a Real-Time Demand Response Asset located at a retail delivery point with no other Real-Time Demand Response Assets at or behind the same retail delivery point, the metered output of any Real-Time Emergency Generation Assets in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response

Asset's Demand Response Baseline. Each generator located behind an individual end-use customer's retail delivery point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between (1) the sum of the asset's actual metered demand as measured at the asset's retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the asset's retail delivery point in the same time intervals, and (2) the asset's Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, for assets that cannot produce net supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Facility Load. For assets that can produce net supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than the maximum amount (MW) that the asset is allowed to push back into the electric system per the applicable generator interconnection agreement (where the amount (MW) pushed back into the electric system is a negative value) and shall not exceed the asset's Maximum Facility Load.

The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval minus the sum of the metered demand measured at the retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of any Real-Time Emergency Generation Assets is greater than its adjusted Demand Response Baseline.

8A.5 Establishing the Demand Response Baseline for a Day with a Scheduled or a Forced Curtailment

8A.5.1 Notification of Forced and Scheduled Curtailments

A Market Participant, with a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset for which a Demand Response Baseline measured at the retail delivery point is utilized, may notify the ISO of a forced curtailment for any reductions in demand that occur as a result of actions outside the control of the Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that is subject to the forced curtailment.

A Market Participant may notify the ISO of a scheduled curtailment at least seven calendar days before the start of any reductions in a Real-Time Demand Response Asset's demand or a Real-Time Emergency Generation Asset's demand where a Demand Response Baseline measured at the retail delivery point is utilized, that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Real-Time Demand Response Assets or Real-Time Emergency Generation Assets with a Maximum Interruptible Capacity of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The length of a scheduled curtailment must be a minimum of a single calendar day and may not exceed a total of 14 calendar days per Capacity Commitment Period.

8A.5.2 Submitting Meter Data Values for Days with Forced or Scheduled Curtailments

For each calendar day on which a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset where a Demand Response Baseline measured at the retail delivery point is utilized, is on a forced or scheduled curtailment, the asset's Demand Designated Entity shall submit to the ISO meter data values equal to the unadjusted baseline calculated for the first day of the forced or scheduled curtailment for all intervals excluding those in which the Real-Time Demand Response Resource with which the Real-Time Demand Response Asset is associated, or the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13, and excluding those in which a Demand Reduction Offer associated with the Real-Time Demand Response Asset had cleared day-ahead or became eligible in real-time pursuant to Section III.E1 on a day with an unanticipated forced curtailment.

8A.5.3 Performance Assessment for Days with Forced or Scheduled Curtailments

To assess the performance of Real-Time Demand Response Assets and Real-Time Emergency Generation Assets that are on a forced or scheduled curtailment, actual meter data values shall be submitted to the ISO for intervals during which the Real-Time Demand Response Resource with which the Real-Time Demand Response Asset is associated, or the Real-Time Emergency

Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13, and intervals in which a Demand Reduction Offer associated with the Real-Time Demand Response Asset was cleared day-ahead or became eligible during the Operating Day pursuant to Section III.E1 on a day with an unanticipated forced curtailment.

III.8B Demand Response Baselines

Section III.8B shall govern Demand Response Baselines calculated for Capacity Commitment Periods commencing on or after June 1, 2017.

A Demand Response Baseline is calculated in 5-minute intervals for each Demand Response Asset and each Real-Time Emergency Generation Asset that is metered at the Retail Delivery Point for the following day types:

(a) weekdays (Monday-Friday) that are non-Demand Response Holidays;
(b) Saturdays, and;
(c) Sundays (including Demand Response Holidays).

8B.1 Demand Response Baseline Calculations

If a Demand Response Asset's metered demand represents Net Supply in an interval, that Net Supply will be used in the Demand Response Baseline calculations for that interval pursuant to Sections III.8B.2 and III.8B.4.

8B.1.1 Demand Response Baseline Real-Time Emergency Generation Asset Adjustment

To the extent a Real-Time Emergency Generation Asset is located at the same Retail Delivery Point as a Demand Response Asset, the metered output of the Real-Time Emergency Generation Asset, in each five-minute interval, shall be added to the metered demand measured at the Retail Delivery Point in the same intervals for purposes of determining the Demand Response Asset's Demand Response Baseline.

8B.2 Establishing an Initial Demand Response Baseline and Resetting a Baseline

An initial Demand Response Baseline will be established for a Demand Response Asset with no previously computed Demand Response Baseline, and for a Real-Time Emergency Generation Asset with no previously computed Demand Response Baseline when a Demand Response Baseline measured at the Retail Delivery Point is utilized for the asset. A Demand Response Baseline will be reset using the initial baseline calculation methodology set forth below when a significant change in load, generation, or reported meter data at an existing Demand Response Asset or Real-Time Emergency Generation Asset occurs.

The initial Demand Response Baseline, or a reset of a Demand Response Baseline, shall be the simple average of metered demand data for the asset for each five-minute interval, subject to the conditions in Section III.8B.1, from the initial 10 days of the same day type. The initial 10 days of meter data used to establish the Demand Response Baseline shall consist of the first 10 consecutive days of the same day type with a complete set of interval meter data.

A Market Participant may not submit Demand Reduction Offers for a Demand Response Resource for a given day type until 1) the month following the establishment of the initial baseline by at least one Demand Response Asset mapped to the Demand Response Resource, provided that the initial baseline was established prior to the last calendar week of the month or, 2) two months following the establishment of the initial baselines for at least one Demand Response Asset mapped to the Demand Response Resource. This condition applies when establishing an initial Demand Response Baseline but not when resetting a Demand Response Baseline.

8B.3 Establishing a Demand Response Baseline for the Next Day

If, for a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for a day type and the asset is associated with a Demand Response Resource that has been dispatched or audited in the present day pursuant to Section III.E2.5 or Section III.13, the Demand Response Baseline of the Demand Response Asset or Real-Time Emergency Generation Asset, in each five-minute interval, for the next day of the same day type is equal to the Demand Response Baseline of that Demand Response Asset or Real-Time Emergency Generation Asset, in the same five-minute interval from the present day.

8B.4 Determing if Meter Data from the Present Day is Used in the Demand Response Baseline for the Next Day of the Same Day Type

If, for a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for that day type, the Demand Response Resource or Real-Time Emergency Generation Resource to which the asset is associated has not been dispatched or audited in the present day pursuant to Section III.E2.5 or Section III.13, or more than seven of the prior 10 days of the same day type have a Demand Response Baseline determined pursuant to Section III.8B.3, then the Demand Response Baseline of the Demand Response Asset or Real-Time Emergency Generation Asset in each five-minute interval, for the next day of the same day type as the present day, is calculated as the sum of 0.9 times the Demand Response Baseline of that Demand Response Asset or Real-Time Emergency Generation Asset for the present day in the same five-minute interval and 0.1 times the Demand Response Asset's or Real-Time Emergency Generation Asset's meter data, subject to the conditions in Section III.8B.1, in the same five-minute interval from the present day.

8B.5 Baseline Adjustment

The Demand Response Baseline for each Demand Response Asset and each Real-Time Emergency Generation Asset is updated approximately every quarter hour by an adjustment factor that is calculated in accordance with this Section III.8B.5, which may increase or decrease the baseline.

(a) An adjustment factor is calculated if the resource with which the asset is associated is not in a period of dispatch (as defined by the resource's Dispatch Instruction including the Demand Response Resource Start-Up Time and Demand Response Resource Notification Time). The adjustment factor is calculated with real-time telemetry data in Real-Time and is calculated with revenue quality metering data for settlement purposes.

(b) For an asset that is part of a resource that is not in a period of dispatch, the adjustment factor is calculated using five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the start of the quarter hour. For an asset that is part of a resource that has received a Dispatch Instruction, the adjustment factor is calculated using five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the Dispatch Instruction was issued. After completion of a dispatch, the adjustment factor for an asset will be calculated using the five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the Dispatch Instruction was issued, until sufficient time has elapsed to calculate the adjustment using post-dispatch interval data.

(c) For a Demand Response Asset, the adjustment factor is equal to the average difference (MW) between the Demand Response Asset's telemetered or metered demand, which shall be adjusted pursuant to Section III.8B.1.1 (inclusive of any Net Supply), and its Demand Response Baseline during the three intervals. For a Real-Time Emergency Generation Asset the adjustment factor is equal to the average difference (MW) between the Real-Time Emergency Generation Asset's telemetered or metered demand and its Demand Response Baseline during the three intervals.

(d) For Demand Response Assets that cannot produce Net Supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load. For Demand Response Assets that can produce Net Supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than the maximum amount (MW) that the asset is allowed to push back into the electric system per the applicable generator interconnection agreement (where the amount (MW) pushed back into the electric system is a negative value) and shall not exceed the asset's Maximum Facility Load.

8B.6 Establishing the Demand Response Baseline for a Day with a Scheduled or a Forced Curtailment

8B.6.1 Notification of Forced and Scheduled Curtailments

A Market Participant, with a Demand Response Asset or a Real-Time Emergency Generation Asset for which a Demand Response Baseline measured at the Retail Delivery Point is utilized, may notify the ISO of a forced curtailment for any reductions in demand that occur as a result of actions outside the control of the Demand Response Asset or Real-Time Emergency Generation Asset that is subject to the forced curtailment.

A Market Participant may notify the ISO of a scheduled curtailment at least seven calendar days before the start of any reductions in a Demand Response Asset's demand or a Real-Time Emergency Generation Asset's demand where a Demand Response Baseline measured at the Retail Delivery Point is utilized, that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Demand Response Assets or Real-Time Emergency Generation Assets with a Maximum Interruptible Capacity of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The length of a scheduled curtailment must be a minimum of a single calendar day and may not exceed a total of 14 calendar days per Capacity Commitment Period.

III.8B.6.2 Submitting Meter Data Values for Days with Forced or Scheduled Curtailments

For each calendar day on which a Demand Response Asset or a Real-Time Emergency Generation Asset, where a Demand Response Baseline measured at the Retail Delivery Point is utilized, is on a forced or scheduled curtailment pursuant to Section III.8B.6.1, the asset's Demand Designated Entity shall submit to the ISO meter data values equal to the unadjusted baseline calculated for the first day of the forced or scheduled curtailment for all intervals excluding those in which:

(a) the Demand Response Resource with which the Demand Response Asset is associated was dispatched during the period of a Shortage Event as defined in Section III.13.7.1.1.1 for the Capacity Zone in which the resource is located,

(b) the Demand Response Resource with which the Demand Response Asset is associated was dispatched in Real-Time pursuant to Section III.E2 on the first day of an unanticipated forced curtailment, or

(c) the Real-Time Emergency Generation Resource with which the Real-Time Emergency Genertion Asset is associated, was dispatched to reduce demand pursuant to Section III.13.

III.8B.6.3 Performance Assessment for Days with Forced or Scheduled Curtailments

To assess the performance of Demand Response Assets and Real-Time Emergency Generation Assets that are on a forced or scheduled curtailment, actual meter data values shall be submitted to the ISO for intervals during which:

(a) the Demand Response Resource with which the Demand Response Asset is associated was dispatched during the period of a Shortage Event as defined in Section III.13.7.1.1.1 for the Capacity Zone in which the Resource is located,

(b) the Demand Response Resource with which the Demand Response Asset is associated was dispatched in Real-Time pursuant to Section III.E2 on the first day of an unanticipated forced curtailment, or

(c) the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13.

III.9 Forward Reserve Market

The Forward Reserve Market is a market to procure TMNSR and TMOR on a forward basis to satisfy forward TMNSR and TMOR requirements.

III.9.1 Forward Reserve Market Timing.

A Forward Reserve Auction will be held approximately two months in advance of each Forward Reserve Procurement Period. The Forward Reserve Auction input parameters and assumptions will be evaluated, published and reviewed with Market Participants prior to the Forward Reserve Auction.

The Forward Reserve Procurement Periods shall be the Winter Capability Period (October 1 through May 31) or the Summer Capability Period (June 1 through September 30), as applicable.

The Forward Reserve Delivery Period shall be hour ending 0800 through hour ending 2300 for each weekday of the Forward Reserve Procurement Period excluding those weekdays that are defined as NERC holidays.

III.9.2 Forward Reserve Market Reserve Requirements.

The ISO shall conduct an advance purchase of capability to satisfy the expected Forward Reserve requirements for the system and each Reserve Zone as calculated by the ISO in accordance with the following procedures and as specified more fully in the ISO New England Manuals. The Forward Reserve Market reserve requirements will be specified as part of the Forward Reserve Auction parameters and will be published and reviewed with Market Participants prior to each Forward Reserve Auction.

III.9.2.1 Forward Reserve Market Reserve Requirements.

The Forward Reserve Market requirements for the New England Control Area will be based on the forecast of the first and second contingency supply losses for the next Forward Reserve Procurement Period and will consist of the following:

(i) One half of the forecasted first contingency supply loss will be specified as the minimum TMNSR to be purchased,

(ii) An additional amount of TMNSR will be added to the minimum TMNSR if system conditions forecasted for the Forward Reserve Procurement Period indicate that the TMNSR available during the period would otherwise be insufficient to meet Real-Time Operating Reserve requirements. The additional amount of TMNSR shall be calculated to account for: (a) any historical under-performance of Resources dispatched in response to a System contingency and (b) the likelihood that more than one half of the forecasted first contingency supply loss will be satisfied using TMNSR.

(iii) One half of the second contingency supply loss will be specified as the minimum TMOR to be purchased,

(iv) An amount of Replacement Reserve in the form of incremental TMOR will be specified in accordance with the Real-Time Replacement Reserve requirement as described in ISO New England Operating Procedure No. 8, Operating Reserve and Regulation and will be added to the minimum TMOR to be purchased.

The requirements specified above, further adjusted to respect the additional provisions described in Section III.9.2.2, represent the set of requirements that will be input into the Forward Reserve Auction.

III.9.2.2 Locational Reserve Requirements for Reserve Zones

Locational reserve requirements will be established for each Reserve Zone. The locational reserve requirements will reflect the need for 30-minute contingency response to provide 2nd contingency protection for each import constrained Reserve Zone. The locational reserve requirements can be satisfied only by Resources that are located within a Reserve Zone and that are capable of providing 30-minute or higher quality reserve products.

The ISO shall establish the locational reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each Reserve Zone for like Forward Reserve Procurement Periods. The ISO will commence the analysis on February 1 or the first business day thereafter for the subsequent summer Forward Reserve Procurement Period and on June 1 or the first business day thereafter for the subsequent winter Forward Reserve Procurement Period.

These daily peak hour requirements will be aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each Reserve Zone will establish the locational requirement.

In the event of a change in the configuration of the transmission system or the addition, deactivation or retirement of a major generating Resource, Dispatchable Asset Related Demand or Demand Response Resource the rolling two-year historical analysis will be calculated in a manner that reflects the change in configuration of the transmission system or the addition, deactivation or retirement of a major generating Resource, Dispatchable Asset Related Demand or Demand Response Resource as of the commencement date of the analysis provided that the following conditions are met:

(a) Change in Configuration of the Transmission System

Any change in the configuration of the transmission system must have been placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the locational reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the locational reserve requirements for the subsequent winter Forward Reserve Procurement Period.

If the change in the configuration of the transmission system consists of a new facility or upgrade of an existing facility, the facility must have operated at an availability level of at least 95% for the period beginning with its in service date and ending on January 31 prior to the summer Forward Reserve Procurement Period or ending on May 31 prior to the winter Forward Reserve Procurement Period.

(b) Addition, Deactivation or Retirement of a Major Generating Resource, Dispatchable Asset Related Demand or Demand Response Resource.

For the addition of a new generating Resource, Dispatchable Asset Related Demand, or Demand Response Resource, the Resource must be placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the locational reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the locational reserve requirements for the subsequent winter Forward Reserve Procurement Period. For the deactivation or retirement of a generating Resource, Dispatchable Asset Related Demand or Demand Response Resource, the Resource must have been removed from service on or before January 31 for inclusion in the analysis for setting the locational reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before May 31 for inclusion in the analysis for setting the locational reserve requirements for the subsequent winter Forward Reserve Procurement Period.

The modified historical data set will be composed of actual data used in the operation of the reconfigured system and historical (pre-reconfiguration) data adjusted for the impact of the system reconfiguration. Pre-reconfiguration data will be revised by substituting values from the historical data set that are no longer valid with corresponding values used in the operation of the reconfigured system.

The locational reserve requirements will be recalculated using the modified historical data set until the rolling two-year historical data set reflects a common system configuration.

III.9.3 Forward Reserve Auction Offers.

Forward Reserve Auction Offers for TMNSR and TMOR shall be (a) made on a $/MW-month basis, (b) made on a Reserve Zone specific basis, (c) made on a non-Resource specific basis and (d) shall be less than or equal to the Forward Reserve Offer Cap. Forward Reserve Auction Offers shall be submitted to the ISO by Market Participants. The Market Participants are responsible for complying with the requirements of this Section III.9 if the Forward Reserve Auction Offer is accepted.

III.9.4 Forward Reserve Auction Clearing and Forward Reserve Clearing Prices.

The Forward Reserve Auction shall simultaneously clear Forward Reserve Auction Offers to meet the Forward Reserve requirements for the system and each Reserve Zone using a mathematical programming algorithm. The objective of the mathematical programming based Forward Reserve Auction clearing is to minimize the total cost of Forward Reserve procured to meet the Forward Reserve requirements. The Forward Reserve Clearing Price for each Reserve Zone will reflect the cost to serve the next increment of reserve in that Reserve Zone based on the submitted offers. The Forward Reserve Auction algorithm substitutes higher quality TMNSR for lower quality TMOR to meet system or Reserve Zone TMOR requirements when it is economical to do so provided that no constraints are violated.

The Forward Reserve Auction algorithm shall also utilize excess Forward Reserve in one Reserve Zone to meet the Forward Reserve requirements of another Reserve Zone or the system provided that the Forward Reserve can be delivered such that no constraints are violated. In addition, the Forward Reserve Auction shall apply price cascading such that the Forward Reserve Clearing Price for TMOR in a Reserve Zone is always less than or equal to the Forward Reserve Clearing Price for TMNSR in that Reserve Zone. If there is insufficient supply to meet the Forward Reserve requirements for a Reserve Zone, the Forward Reserve Clearing Price for that Reserve Zone will be set to the Forward Reserve Offer Cap.

III.9.4.1 Forward Reserve Clearing Price and Forward Reserve Obligation Publication and Correction.

Market Participants with cleared Forward Reserve Auction Offers will receive a Forward Reserve Obligation for each Reserve Zone, as applicable, that is equal to the amount of Forward Reserve megawatts cleared for that Market Participant adjusted for internal bilateral transactions that transfer Forward Reserve Obligations.

(a) Within five business days after the close of the Forward Reserve Auctions, the ISO shall post Forward Reserve Clearing Prices and Forward Reserve Obligations, which shall be final as posted, not subject to correction or other adjustment, and used for the purposes of settlement, except as provided in subsections (c) and (d). The permissibility of correction of errors in sections of Market Rule 1 relating to settlement and billing processes shall not apply to Forward Reserve Clearing Prices and Forward Reserve Obligations deemed final pursuant to this Section III.9.4.1.

(b) Before posting the final Forward Reserve Clearing Prices and Forward Reserve Obligations, the ISO shall make a good faith effort when clearing those markets to discover and correct any errors that may occur due to database, software or similar errors of the ISO or its systems before publishing the final prices awarded.

(c) If the ISO determines based on reasonable belief that there may be one or more errors in the final Forward Reserve Clearing Prices and Forward Reserve Obligations or if no Forward Reserve Clearing Prices and Forward Reserve Obligations are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 11:59 p.m. of the third business day following the posting deadline specified in subsection (a), a notice that the Forward Reserve Clearing Prices and Forward Reserve Obligations are provisional and subject to correction or unavailable for initial publishing. The ISO shall confirm within three business days of posting a notice pursuant to this subsection whether there was an error in the Forward Reserve Clearing Prices and Forward Reserve Obligations and shall post a notice stating its findings.

(d) Within three business days after posting an initial notice pursuant to subsection (c); the ISO shall either: (1) publish final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations, or: (2) in the event that the ISO is unable to calculate and post final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations due to exigent circumstances not contemplated in this market rule, make an emergency filing with the Commission detailing the exigent circumstance which will not allow final Forward Reserve Clearing Prices and Forward Reserve Obligations to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

III.9.5 Forward Reserve Resources

III.9.5.1 Assignment of Forward Reserve MWs to Forward Reserve Resources.

(a) Prior to the close of the Re-Offer Period for each Operating Day of the Forward Reserve Procurement Period, Market Participants must convert their Forward Reserve Obligations into Resource-specific obligations by assigning Forward Reserve MWs to specific eligible Forward Reserve Resources, in accordance with procedures set forth in the ISO New England Manuals. The assignment of Forward Reserve MWs to a Forward Reserve Resource must be performed by the Lead Market Participant for the Resource.

(b) A Market Participant with a Forward Reserve Obligation must have an Ownership Share in a Forward Reserve Resource that is a generating Resource in order to assign Forward Reserve MWs to that Forward Reserve Resource to fulfill that Market Participant's Forward Reserve Obligation. If more than one Market Participant has an Ownership Share in a Forward Reserve Resource, the Forward Reserve MWs assigned to that Resource will be allocated pro-rata to Market Participants by Ownership Share.

III.9.5.2 Forward Reserve Resource Eligibility Requirements.

(a) Forward Reserve Resources are Resources that have been assigned by Market Participants to meet their Forward Reserve Obligations. To be eligible as a Forward Reserve Resource, a Resource must satisfy the following criteria:

(i) If the generating Resource is off-line, it must be a Fast Start Generator and have an audited CLAIM10 or CLAIM30 value established pursuant to Section III.9.5.3;

(ii) If the Resource is a Demand Response Resource which has not been dispatched, it must be a Fast Start Demand Response Resource and have an audited CLAIM10 or CLAIM30 value established pursuant to Section III.9.5.3;

(iii) If the generating Resource is expected to be on-line, or, for a Demand Response Resource, has been dispatched, during a Forward Reserve Delivery Period, it must be able to produce the energy or demand reduction equivalent to its assigned Forward Reserve Obligation within the timeframe of the assigned Forward Reserve Obligation when operating within its dispatch range;

(iv) If the Resource is an Asset Related Demand, it must have a CLAIM10 or CLAIM30 value established pursuant to Section III.9.5.3;

(v) Any portion of the Resource to which a Forward Reserve Obligation has been assigned that is without a Capacity Supply Obligation must not have been offered to support an External Transaction sale during the Operating Day for which it has been assigned;

(vi) The Resource must have Electronic Dispatch Capability;

(vii) The Resource must followDispatch Instructions during the Operating Day. The Resource must meet the technical requirements associated with the provision of Forward Reserve as specified in ISO New England Operating Procedure No. 14, (Technical Requirements for Generators, Demand Resources and Asset Related Demands);

(viii) The portion of the Resource that is assigned a Forward Reserve Obligation for any portion of an Operating Day must be eligible to provide Operating Reserve in accordance with the provisions of Section III.10.1.1;

(ix) The portion of the Resource to which a Forward Reserve Obligation has been assigned must be offered into the Real-Time Energy Market in accordance with the provisions of either Section III.13.6.1.1.2 or Section III.13.6.1.5.2.

(b) External Resources will be permitted to participate in the Forward Reserve Market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.9.5.3 Resource CLAIM10 and CLAIM30 Values.

III.9.5.3.1 Calculating Resource CLAIM10 and CLAIM30 Values.

1. The CLAIM10 or CLAIM30 value of a Resource shall equal:

(a) the maximum output or demand-reduction level reached, including the level reached during a CLAIM10 or CLAIM30 audit, measured at the 10 minute or 30 minute point from the Resource's receipt of an initial electronic startup Dispatch Instruction during the current Forward Reserve Procurement Period or the preceding like-season Forward Reserve Procurement Period, subject to the conditions in Section III.9.5.3.1.2 below;

(b) multiplied by the Resource's then effective CLAIM10 or CLAIM30 performance factor established pursuant to Section III.9.5.3.3.

2. The value in Section III.9.5.3.1.1(a) is subject to the following additional conditions:
   (a) The value shall not include any dispatch in which the unit becomes unavailable within 60 minutes following the receipt of the initial Dispatch Instruction;

   (b) If the maximum output or demand-reduction level reached, as measured at the 10 minute or 30 minute point from the initial Dispatch Instruction, is greater than the highest Desired Dispatch Point issued for the Resource for that 10 minute or 30 minute period, the value shall be capped at the highest Desired Dispatch Point.

3. A Resource's CLAIM10 value shall be no greater than the Resource's CLAIM30 value.

4. The CLAIM10 or CLAIM30 value of a Resource shall be calculated and distributed to the Lead Market Participant weekly and shall become effective at 0001 of the Monday following the distribution.

III.9.5.3.2 CLAIM10 and CLAIM30 Audits.

(a) **General.** A Market Participant may request a CLAIM10 or CLAIM30 audit specifying the requested output or demand-reduction level that the Resource will attempt to reach in 10 or 30 minutes. A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(b) **CLAIM10 and CLAIM30 Audit Procedures.** The ISO will initiate a CLAIM10 or CLAIM30 audit by issuing an electronic Dispatch Instruction without providing prior notice to the Market Participant. The ISO will normally perform the audit, at any time during the Forward Reserve Delivery Period, within five business days of receipt of the audit request or will advise the Market Participant if it will be unable to initiate the audit during the five business day period. The Resource's CLAIM10 or CLAIM30 audit value shall be the Resource's output or demand-reduction level reached at the 10 minute or 30 minute point after the receipt of the initial startup Dispatch Instruction.

III.9.5.3.3 CLAIM10 and CLAIM30 Performance Factors.

A Resource's CLAIM10 or CLAIM30 performance factor shall be established based upon the 10 most recent ISO-issued initial electronic startup Dispatch Instructions as described below. Dispatches greater than three years old shall not be used for the performance factor calculation. Resource performance factors will be calculated on a weekly basis.

(a) A Resource's performance factor is calculated as:

$$performance\ factor = \frac{\sum_{n=1}^{10}\left(\frac{resource\ output\ or\ demand\ reduction\ at\ 10\ or\ 30\ minutes_n\ (MW)}{resource\ target\ value_n\ (MW)} * n\right)}{\sum_{n=1}^{10} n}$$

Where:

n is a value between 1 and 10, 1 representing the least recent dispatch signal, 10 representing the most recent dispatch signal;

the Resource output or demand reduction is measured at the 10 minute or 30 minute point from receipt of the initial startup Dispatch Instruction;

the Resource target value is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute or 30 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM10 or CLAIM30 value or (iii) the Resource's Offered CLAIM10 or Offered CLAIM30.

(b) For purposes of the performance factor calculation, the following conditions apply:

(i) For each CLAIM10 or CLAIM30 audit, the Resource's target value shall be set to the Resource's output or demand reduction at 10 or 30 minutes.

(ii) In the event the Resource has not had 10 electronic startup dispatches within the last three years, the “n” term in the performance factor calculation will be based on the number of startup dispatches that took place in the last three years, with the most recent dispatch having a weight of 10 and with the weighting decreasing by 1 for each previous startup dispatch.

(iii) If a Resource’s output or demand reduction at 10 or 30 minutes is greater than the Resource’s target value, then the Resource target value shall be set to the Resource output at 10 or 30 minutes.

(iv) A dispatch shall not be utilized in the performance factor calculation if a Resource starts and subsequently performs a normal shut down or ceases its demand reduction, in response to a Dispatch Instruction to shut down or, for a Demand Response Resource, in response to a Dispatch Instruction to cease its demand reduction, within the 10 or 30 minute period following the initial electronic startup Dispatch Instruction.

(v) Resource output or demand reduction at 10 or 30 minutes shall equal zero if the Resource becomes unavailable for dispatch within the 60 minute period following the initial electronic startup Dispatch Instruction.

III.9.5.3.4 Performance Factor Cure.

In the event a Resource either (a) is unable to reach at least 60% of the Resource target level, as reflected in the Dispatch Instruction issued for the Resource, either five times in a row or seven out of 10 times, as a result of a chronic operational problem with the Resource or (b) undergoes a major overhaul scheduled and performed during a planned outage that was approved in the ISO’s annual maintenance scheduling process or during a scheduled curtailment for a Demand Response Resource, a Market Participant may submit a restoration plan to the ISO to restore the Resource’s CLAIM10 or CLAIM30 operational capability. Restoration plans submitted because of a Resource’s inability to reach its target output or demand reduction shall indicate the specific nature of the problem, the steps to be taken to remedy the problem, and the timeline for completing the restoration. Restoration plans submitted for a major overhaul shall explain the actions taken during the planned outage or scheduled curtailment that would result in the increase of the Resource’s CLAIM10 or CLAIM30. The ISO shall accept restoration plans that, upon review, indicate a reasonable likelihood of success in remedying the identified problem or, for a major overhaul, increasing the Resource's CLAIM10 or CLAIM30. Upon completion of the restoration, the Market Participant shall request a CLAIM10 or CLAIM30 audit of the Resource, using the procedures in Section III.9.5.3.2. Following the audit, the Resource's Performance Factor shall be set to 1.0, with all dispatches prior to the audit removed from the performance factor calculation.

III.9.6 Delivery of Reserve.

III.9.6.1 Dispatch and Energy Bidding of Reserve.

Forward Reserve shall be delivered by Forward Reserve Resources for an hour by offering the capability into the Real-Time Energy Market by submitting Supply Offers and Demand Bids no later than 30 minutes prior to the start of the operating hour at or above the Forward Reserve Threshold Price for the Operating Day. Day-Ahead Energy Market Supply Offers and Demand Bids for Resources to which Forward Reserve Obligations have been assigned will be used in the Real-Time Energy Market for the associated Operating Day even if the Supply Offers do not clear the Day-Ahead Energy Market, notwithstanding the requirements of Section III.13.6.2.1.1.2, unless superseded by a more recent Supply Offer or Demand Bid submitted no later than 30 minutes prior to the start of the operating hour. A Market Participant is not required to submit a Supply Offer or Demand Bid into the Day-Ahead Energy Market for a Resource without a Capacity Supply Obligation in order for the Resource to be eligible to be a Forward Reserve Resource. The Forward Reserve Threshold Prices shall be set in accordance with the ISO New England Manuals so that Forward Reserve Resource capability has (a) a low probability of being dispatched for energy and (b) a high probability of being held for reserve purposes.

Forward Reserve shall be delivered by Forward Reserve Resources that are Demand Response Resources for an hour by offering the capability into the Real-Time Energy Market by submitting Demand Reduction Offers no later than the close of the Re-Offer Period at or above the Forward Reserve Threshold Price for the Operating Day. Day-Ahead Energy Market Demand Reduction Offers for Demand Response Resources to which Forward Reserve Obligations have been assigned will be used in the Real-Time Energy Market for the associated Operating Day even if the Demand Reduction Offers do not clear the Day-Ahead Energy Market, notwithstanding the requirements of Section III.13.6.1.5.2.

Forward Reserve Resources are scheduled and operated in accordance with Section III.1 of Market Rule 1; no distinction is made due to their status as Forward Reserve Resources. Forward Reserve Resources are eligible to set the Locational Marginal Price in accordance with Section III.2 of Market Rule 1.

III.9.6.2 Forward Reserve Threshold Prices.

The formula for determining the Forward Reserve Threshold Prices shall be fixed for the duration of the Forward Reserve Procurement Period. The ISO will reevaluate the Forward Reserve Threshold Price level for successive Forward Reserve Auctions on the basis of experience, expected operating conditions and other relevant information.

Forward Reserve Threshold Price: is calculated as the Forward Reserve Heat Rate multiplied by the daily Forward Reserve Fuel Index.

Forward Reserve Heat Rate: shall be fixed for the duration of the Forward Reserve Procurement Period and announced in the announcement for the Forward Reserve Auction. New Forward Reserve Heat Rates shall be specified for successive auctions, and shall be the lesser of: (a) the value determined in accordance with applicable ISO New England Manuals; or (b) the heat rate defined for the PER Proxy Unit in Section III.13.7.2.7.1.1.1(b) less 1 Btu/kWh.

Forward Reserve Fuel Index: is a daily fuel index, or combination of daily indices, applicable to the New England Control Area and specified in the announcement of the Forward Reserve Auction.

III.9.6.3 Monitoring of Forward Reserve Resources.

In accordance with Section III.A.13.4, the Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Participant in accordance with Section III.A.3. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4.

III.9.6.4 Forward Reserve Qualifying Megawatts.

Qualifying megawatts for generating Resources and Dispatchable Asset Related Demand are calculated separately on an hourly basis for Forward Reserve Resources supplying Forward Reserve from an off-line state and Forward Reserve Resources supplying Forward Reserve from an on-line state as follows:

Off-line qualifying megawatts. Off-line qualifying megawatts are the amount of capability equal to or below the Economic Maximum Limit for an off-line Forward Reserve Resource offered at or above the

Forward Reserve Threshold Price. The generating Resource must satisfy this requirement in the Real-Time Energy Market. In the case of off-line Forward Reserve Resources, the calculation for Forward Reserve Qualifying Megawatts shall include both the energy Supply Offer and a pro-rated amount of Start-Up Fees and No-Load Fees as defined below.

An off-line Forward Reserve Resource must offer its capability so that the following holds:

$$\frac{StartUp}{EcoMax \times 1\ hour} + \frac{NoLoad}{EcoMax} + Energy\ Offer_i \geq ForwardReserveThresholdPrice$$

where:

StartUp	= the generating Resource's cold Start-Up Fee.
NoLoad	= the generating Resource's No-Load Fee.
$EnergyOffer_i$	= the generating Resource's Energy Offer for Energy Offer block $_i$.
EcoMax	= the Economic Maximum Limit.

<u>On-line qualifying megawatts</u>: is the capability that is less than or equal to the Economic Maximum Limit and above the Economic Minimum Limit that is offered at or above the applicable Forward Reserve Threshold Price by an on-line generating Resource or, is the capability that is less than or equal to the Maximum Consumption Limit and greater than the Minimum Consumption Limit offered at or above the applicable Forward Reserve Threshold Price for a Dispatchable Asset Related Demand. The Forward Reserve Resource must satisfy this requirement in the Real-Time Energy Market. For an on-line generating Resource that has been assigned to meet a Forward Reserve Obligation and has not cleared in the Day-Ahead Energy Market and is operating in a delivery hour as the result of an ISO commitment for VAR or local second contingency protection, the on-line qualifying megawatts shall be zero.

Qualifying megawatts for Demand Response Resources supplying Forward Reserve are calculated separately on an hourly basis for Demand Response Resources that have not been dispatched and Demand Response Resources that have been dispatched as follows:

Qualifying megawatts for a Demand Response Resource that has not been dispatched: is the amount of capability equal to or below the Maximum Reduction for the Demand Response Resource offered at or above the Forward Reserve Threshold Price. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. In the case of Demand Response Resources that have not been dispatched, the calculation for Forward Reserve Qualifying Megawatts shall include both the Demand Reduction Offer price and a pro-rated amount of the Interruption Cost as defined below.

A Demand Response Resource that has not been dispatched must offer its capability so that the following holds:

$$\frac{Interruption\ Cost}{MaxRed} + Energy\ Offer_{i} \geq Forward\ Reserve\ Threshold\ Price$$

where:

Interruption Cost = the amount, in dollars, that must be paid each time the Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

$EnergyOffer_i$ = the Resource's Demand Reduction Offer price for Energy Offer block $_i$.

Max Red = the Resource's Maximum Reduction x 1 hour.

Qualifying megawatts for a Demand Response Resource which has been dispatched: is the capability that is less than or equal to the Maximum Reduction and greater than the Minimum Reduction that is offered at or above the applicable Forward Reserve Threshold Price for the Demand Response Resource. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. For a Demand Response Resource which has been dispatched, has been assigned to meet a Forward Reserve Obligation, has not cleared in the Day-Ahead Energy Market, and is operating in a delivery hour as the result of an ISO commitment for local second contingency protection, the qualifying megawatts shall be zero.

III.9.6.5 Delivery Accounting.

Forward Reserve Delivered Megawatts are the quantity of Forward Reserve delivered in each hour of the Real-Time Energy Market to each Reserve Zone and is calculated as follows.

(a) Forward Reserve Delivered Megawatts for an off-line generating Forward Reserve Resource are calculated in megawatts for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount, in MW, of Forward Reserve that the off-line generating Resource can provide, based upon CLAIM10 and CLAIM30 values provided in the generating Resource's Real-Time Supply Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (energy at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(b) Forward Reserve Delivered Megawatts for an on-line generating Resource are calculated in megawatts for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramping rate of the on-line generating Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(c) Forward Reserve Delivered Megawatts for a Dispatchable Asset Related Demand are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramp rate of the Resource, as applicable,

(ii) the amount of Forward Reserve capability specified in the Resource's CLAIM10 and CLAIM30 values,

(iii) Forward Reserve Assigned Megawatts, or

(iv) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2),

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(d) A Forward Reserve Resource's hourly Forward Reserve Delivered Megawatts for each Reserve Zone is calculated as the sum of the Market Participant's Resource specific hourly Forward Reserve Delivered Megawatts for each Reserve Zone.

(e) Resource specific Forward Reserve Delivered Megawatts for TMNSR within a Reserve Zone will be applied first to a Market Participant's higher value Forward Reserve Obligation for TMNSR in that Reserve Zone. Any surplus Forward Reserve Delivered Megawatts for TMNSR in that Reserve Zone will be applied to meet the Market Participant's Forward Reserve Obligation for TMOR in that Reserve Zone. Forward Reserve Delivered Megawatts remaining within that Reserve Zone after the Market Participant's Forward Reserve Obligation for that Reserve Zone have been met is available to be applied to the Market Participant's Forward Reserve Obligations in other Reserve Zones provided that the Forward Reserve Delivered Megawatts can be delivered to the other Reserve Zones.

(f) Forward Reserve Delivered Megawatts for a Demand Response Resource which has not been dispatched are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount of Forward Reserve that the Resource can provide, based upon CLAIM10 and CLAIM30 values provided in the Demand Response Resource's Demand Reduction Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (energy at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(g) Forward Reserve Delivered Megawatts for a Demand Response Resource which has been dispatched are calculated for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute Demand Response Resource Ramp Rate of that Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(h) In determining Forward Reserve Delivered Megawatts for Demand Response Resources the portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be multiplied by one plus the average avoided peak distribution losses.

(i) It will be assumed that all Demand Response Assets associated with a Demand Response Resource must first reduce their load from the electricity system before providing Net Supply.

- (ii) The portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be the lesser of: Forward Reserve Delivered Megawatts, or
- The amount of load that the Demand Response Asset associated with a Demand Response Resource can reduce from the electric system as indicated from revenue quality meter data.

(iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with Net Supply will be capped at the Net Supply Limit.

III.9.7 Consequences of Delivery Failure.

III.9.7.1 Real-Time Failure-to-Reserve.

A Real-Time Forward Reserve Failure-to-Reserve 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.

(a) Forward Reserve Failure-to-Reserve Megawatts: A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMNSR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(i) Market Participant Forward Reserve Obligation for TMNSR for that Reserve Zone minus the Market Participant's Forward Reserve Delivered Megawatts for TMNSR for that Reserve Zone; and

(ii) Zero.

A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMOR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(i) Market Participant Forward Reserve Obligation for TMOR for that Reserve Zone minus Market Participant's Forward Reserve Delivered Megawatts for TMOR for that Reserve Zone; and

(ii) Zero.

(b) Forward Reserve Failure-to-Reserve Penalties: A Market Participant's Forward Reserve Failure-to-Reserve Penalty for a Reserve Zone in an hour is defined as:

(i) Forward Reserve Failure-to-Reserve Penalty for TMNSR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Reserve Penalty for TMOR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Reserve Penalty Rate (calculated for each Forward Reserve product and for each Reserve Zone) = maximum of (1.5 multiplied by the Forward Reserve Payment Rate for the Forward Reserve product, the applicable Real-Time Reserve Clearing Price for the Forward Reserve product in the Reserve Zone minus the Forward Reserve Payment Rate for the Forward Reserve product)

III.9.7.2 Failure-to-Activate Penalties.

Market Participants are required to pay a Forward Reserve Failure-to-Activate Penalty for each Forward Reserve Resource that fails to activate its Forward Reserve capability. For Forward Reserve Resources:

- providing TMNSR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction as part of the real-time contingency dispatch algorithm, or;
- providing TMOR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction when the ten-minute reserve requirement is binding or violated in an approved UDS case.

If a Market Participant's Forward Reserve Resource fails to activate Forward Reserve, which determination shall be made in accordance with subsection (a), that Market Participant shall be required to pay a Forward Reserve Failure-to-Activate Penalty associated with that Resource pursuant to subsection (b):

(a) **Forward Reserve Failure-to-Activate Megawatts**:

A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMNSR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(i) Maximum of Forward Reserve Delivered Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

(ii) Maximum of Target Activation Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMNSR from off-line Forward Reserve Resources or Demand Response Resources that are not dispatched, which are subsequently dispatched as part of the real-time contingency dispatch algorithm is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM10 or; (iii) the Resource's Offered CLAIM10.

Target Activation Megawatts for TMNSR from on-line Forward Reserve Resources dispatched, or Demand Response Resources that have been dispatched, as part of the real-time contingency dispatch algorithm is the lesser of: (i) the Resource's Manual Response Rate or Demand Response Resource Ramp Rate times 10 minutes or (ii) the Resource's Economic Maximum Limit or Maximum Reduction minus the Resource's initial output or demand reduction at activation, or; (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource's initial output or demand reduction at activation.

The actual amount of TMNSR energy delivered during activation is measured at the 10 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMNSR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMOR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(i) Maximum of Forward Reserve Delivered Megawatts for TMOR plus Forward Reserve Delivered Megawatts for TMNSR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

(ii) Maximum of Target Activation Megawatts for TMOR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMOR from off-line Forward Reserve Resources or Demand Response Resources that are not dispatched is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM30, or; (iii) the Resource's Offered CLAIM30.

Target Activation Megawatts for TMOR from on-line Forward Reserve Resources, or Demand Response Resources that have been dispatched, is the lesser of: (i) the Resource's Manual Response Rate or Demand Response Resource Ramp Rate times 30 minutes or (ii) the Resource's Economic Maximum Limit or Maximum Reduction minus the Resource's initial output or demand reduction at activation, or; (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial output or demand reduction at activation.

The actual amount of TMOR energy delivered during activation is measured at the 30 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMOR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

In determining the Target Activation Megawatts for Demand Response Resources, the portion of the Target Activation Megawatts not associated with Net Supply shall be multiplied by one plus the average avoided peak distribution losses.

The portion of the Target Activation Megawatts not associated with Net Supply is the lesser of:

- Target Activation Megawatts, or
- The amount of load reduced during activation.

The portion of the Target Activation Megawatts associated with Net Supply is the lesser of:

- Target Activation Megawatts less the Target Activation Megawatts not associated with Net Supply, or
- The amount of Net Supply that the Demand Response Resource produced during activation.

A Forward Reserve Resource that is a Fast Start Generator that fails to activate Forward Reserve through a failure to start , or a Forward Reserve Resource that is a Fast Start Demand Response Resource that fails to activate Forward Reserve through a failure to provide a demand reduction, shall have its Forward Reserve Delivered Megawatts set equal to zero in each subsequent hour in the applicable Forward Reserve Delivery Period until such time that the Market Participant notifies the ISO that the Forward Reserve Resource is capable of providing the Forward Reserve Delivered Megawatts.

(b) **Forward Reserve Failure-to-Activate Penalties:**

A Market Participant's Forward Reserve Failure-to-Activate Penalty for a Resource in an hour is defined as:

(i) Forward Reserve Failure-to-Activate Penalty for TMNSR = The sum of the Forward Reserve Payment Rate for TMNSR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Activate Penalty for TMOR = The sum of the Forward Reserve Payment Rate for TMOR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Activate Penalty Rate = Maximum of 2.25 multiplied by the Forward Reserve Payment Rate, or the applicable nodal LMP.

III.9.7.3 Known Performance Limitations.

The ISO may have reason to believe that a particular Forward Reserve Resource is frequently receiving, or may frequently receive, Forward Reserve payments for a portion or all of its capability that is not capable of activating the Forward Reserve Assigned Megawatts for TMNSR or the Forward Reserve Assigned Megawatts for TMOR. When the ISO believes there is such a limited Forward Reserve Resource, the ISO shall contact and confer with the affected Market Participant before taking any action.

(a) The ISO will, whenever practicable, contact the affected Market Participant of the Forward Reserve Resource to request an explanation of the relevant resource Offer Data;

(b) If the explanation, if available, considered together with other information available to the ISO, indicates to the satisfaction of the ISO that the questioned Forward Reserve payments are consistent with Forward Reserve Resource capabilities, no further action will be taken; and

(c) If no agreement is reached, or an acceptable explanation is not provided, the Market Participant may request a Resource performance audit. If the Forward Reserve Resource fails the performance audit or the Market Participant refuses to request a Resource performance audit, the ISO may take remedial action. Remedial actions may include, but are not limited to: (i) redeclaration, by the ISO, of any relevant operational Offer Data parameter, or (ii) removing the Resource or the relevant portion of the Resource's capability to provide Forward Reserve on a going-forward basis.

III.9.8 Forward Reserve Credits.

Payment for Forward Reserve is based upon a Market Participant's Final Forward Reserve Obligation and the applicable Forward Reserve Clearing Prices. The ISO shall calculate these credits on an hourly basis for each Reserve Zone as follows:

(a) Final Forward Reserve Obligations for TMNSR and TMOR for each Market Participant are calculated for each Reserve Zone for each hour as follows:

(i) Final Forward Reserve Obligation = minimum [Forward Reserve Obligation, Forward Reserve Delivered Megawatts]

(b) $FCACP_{Zone}$ and $FRACP_{Zone}$ are defined as:

$FCACP_{Zone}$ for a Reserve Zone is the Forward Capacity Auction Capacity Clearing Price for the Capacity Zone in which the Reserve Zone is contained.

$FCACP_{Zone}$ for the Rest of System is the maximum Forward Capacity Auction Capacity Clearing Price for all Capacity Zones included in whole or in part in the Rest of System.

$FRACP_{Zone}$ is the Forward Reserve Clearing Price for the relevant Reserve Zone, for TMNSR or TMOR, respectively;

(c) Market Participant Forward Reserve Credit for TMNSR=Final Forward Reserve Obligation for TMNSR multiplied by the applicable hourly Forward Reserve Payment Rate for TMNSR;

where,

the hourly Forward Reserve Payment Rate for TMNSR is equal:

maximum of [(applicable monthly $FRACP_{Zone}$ for TMNSR – $FCACP_{Zone}$), 0] divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

(d) Market Participant Forward Reserve Credit for TMOR = Final Forward Reserve Obligation for TMOR multiplied by the applicable hourly Forward Reserve Payment Rate for TMOR; where,

the hourly Forward Reserve Payment Rate for TMOR is equal to:

maximum of [(applicable monthly $FRACP_{Zone}$ for TMOR - $FCACP_{zone}$),0] divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

III.9.9 Forward Reserve Charges.

Forward Reserve Charges are allocated to each Market Participant in two steps. The first step allocates the Forward Reserve Credits associated with the procurement of reserves to meet the Forward Reserve requirement for the system. The second step, if necessary, allocates any remaining Forward Reserve Credits.

III.9.9.1 Forward Reserve Credits Associated with System Reserve Requirement.

The portion of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is determined by simulating a Forward Reserve Auction using all submitted Forward Reserve Auction Offers to meet only the Forward Reserve Market minimum requirements for the New England Control Area pursuant to Section III.9.2.1. The simulated Forward Reserve Auction will clear offers pursuant to the methodology set forth in Section III.9.4 to calculate TMNSR and TMOR proxy system clearing prices. The TMNSR and TMOR proxy system clearing prices will reflect the cost to serve the next increment of reserve above the Forward Reserve Market minimum requirement for the New England Control Area.

For each hour, the total amount of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is calculated as the lesser of:

(i) The TMNSR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the maximum of the [TMNSR proxy system clearing price reduced by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, 0], plus the TMOR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the maximum of the [TMOR proxy system clearing price reduced by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, 0] and divided by the number of hours in the month associated with the Forward Reserve Delivery Period, or

(ii) Total Forward Reserve Credits for the New England Control Area as calculated pursuant to Section III.9.8.

III.9.9.2 Adjusting Forward Reserve Credits for System Requirement.

For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is reduced by:

(i) Any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in the Rest of System or in a Load Zone that is ineligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, and

(ii) A prorated amount of any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in a Load Zone that is eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.3 Allocating Forward Reserve Credits for System Requirements.

For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirements for the system as calculated pursuant to Section III.9.9.1, is reduced by any penalties calculated pursuant to Section III.9.9.2, and allocated on a pro rata basis using each Market Participant's share of Real-Time Load Obligation in each Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Real-Time Reserve Designations associated with Dispatchable Asset Related Demands within that Load Zone.

III.9.9.4 Allocating Remaining Forward Reserve Credits.

For each hour, any Forward Reserve Credits not allocated pursuant to Section III.9.9.3 are allocated on a pro rata basis to each Market Participant's share of Real-Time Load Obligation in a Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Real-Time Reserve Designations associated with Dispatchable Asset Related Demands within that Load Zone) that meets the criteria in Section III.9.9.4.1. The allocation for each Load Zone is based on the ratio of the Forward Reserve Credits cleared in the Respective Reserve Zone for the Forward Reserve Credits cleared in all Reserve Zones that meet the criteria in Section III.9.9.4.1, and is reduced by:

(i) A prorated amount of any Forward Reserve Failure-to-Reserve Penalties or Forward Reserve Failure-to-Activate Penalties that occur in a Load Zone eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of the total Forward Reserve Credits less any Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.4.1 Allocation Criteria for Remaining Forward Reserve Credits.

If the following criteria are met, then a Market Participant with Real-Time Load Obligation in a Load Zone is eligible to receive any remaining Forward Reserve Credits not allocated pursuant to Section III.9.9.3.

(i) The Load Zone is encompassed in whole or in part in a Reserve Zone with a locational reserve requirement greater than zero, and

(ii) The Forward Reserve Clearing Price of a Reserve Zone is higher than the Forward Reserve Clearing Price of the Rest of System.

III.10 Real-Time Reserve

The ISO shall use a joint optimization dispatch algorithm to serve Real-Time Energy Market requirements and meet Real-Time Operating Reserve requirements based on a least-cost security constrained economic dispatch. The Real-Time dispatch algorithm will designate Resources to meet the Energy requirements and will designate Resources to meet the Operating Reserve requirements of the New England Control Area.

III.10.1 Provision of Operating Reserve in Real-Time

For each Market Participant for each hour, the ISO will determine each Market Participant's provision of Operating Reserve in Real-Time. To accomplish this, the ISO will perform calculations to determine the following.

III.10.1.1 Real-Time Reserve Designation

Each Market Participant shall have for each hour and for each eligible generating Resource capable of providing Operating Reserve a Real-Time Reserve Designation, in megawatts, equal to the amounts of Operating Reserve designated by the ISO to that Resource in Real-Time adjusted downward after-the-fact, if necessary, to account for differences in actual Resource output based upon revenue quality meter readings and the estimated Resource output utilized to determine the amount of Real-Time Reserve Designation. Each Market Participant shall have for each hour and for each eligible Asset Related Demand Resource or Demand Response Resource capable of providing Operating Reserve a Real-Time Reserve Designation, in megawatts, equal to the amounts of Operating Reserve designated by the ISO to that Resource in Real-Time adjusted downward after-the-fact, if necessary, to account for differences in actual Operating Reserve capability based upon revenue quality meter readings and the estimated Operating Reserve capability utilized to determine the amount of Real-Time Reserve Designation. Resource eligibility to provide Operating Reserve shall be specified in the ISO New England Manuals.

III.10.2 Real-Time Reserve Credits

For each Market Participant for each hour, the ISO will determine a credit for provision of Operating Reserve in Real-Time.

(a) A Market Participant's Resource specific Real-Time Reserve Credit for TMSR shall be equal to that Market Participant's Resource specific Real-Time Reserve Designation for TMSR multiplied by the Real-Time Reserve Clearing Price for TMSR. The Real-Time Reserve Credit for TMSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMSR in that Load Zone.

(b) A Market Participant's Resource specific Real-Time Reserve Credit for TMNSR shall be equal to that Market Participant's Resource specific Real-Time Reserve Designation for TMNSR multiplied by the Real-Time Reserve Clearing Price for TMNSR. The Real-Time Reserve Credit for TMNSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMNSR in that Load Zone.

(c) A Market Participant's Resource specific Real-Time Reserve Credit for TMOR shall be equal to that Market Participant's Resource specific Real-Time Reserve Designation for TMOR multiplied by the Real-Time Reserve Clearing Price for TMOR. The Real-Time Reserve Credit for TMOR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMOR in that Load Zone.

III.10.3 Real-Time Reserve Charges.

(a) For each hour, the ISO will allocate the sum of the Real-Time Reserve Credits and Forward Reserve Obligation Charges for each Load Zone, calculated separately for TMSR, TMNSR and TMOR, to each Market Participant as follows:

Real-Time Reserve $\text{Charge}_{k,i}$ = [Reserve Charge Allocation $\text{MW}_{k,I}$] x [RT_CHRG_RT_{i}]

Where:

Real-Time Reserve $\text{Charge}_{k,i}$, is Market Participant *k's* Real-Time Reserve Charge for Load Zone *i* for all Real-Time reserve services and Forward Reserve Obligation Charges;

Reserve Charge Allocation MW = Market Participant *k's* Real Time Load Obligation in Load Zone *i* adjusted for Market Participant *k's* Dispatchable Asset Related Demand MWs in Load Zone *i* that are designated for Real-Time reserves.

RT_CHRG_RT_{i} = [IRT_SUP_PMNT]/RT_P_WTD_LD_OB] x
[RT_P_RATIO] for TMSR, TMNSR, or TMOR, as applicable.

RT_P_WTD_LD_OB = ∑[Reserve Charge Allocation MW_{si}] x
[P_RATIO_{i}] for TMSR, TMNSR or TMOR, as applicable;

[RT_SUP_PMNT] = The total over all Load Zones of Real-Time Reserve Credits for TMSR, TMNSR or TMOR, plus the total over all Load Zones of the Forward Reserve Obligation Charges for TMNSR or TMOR, as applicable;

RT_P_RATIOi is the ratio of the Real Time Reserve Clearing Price in Load Zone i for TMSR, TMNSR or TMOR, as applicable, to the Real -Time Reserve Clearing Price in the Reference Zone for TMSR, TMNSR or TMOR, as applicable. To the extent that a Load Zone contains more than one Reserve Zone, that Load Zone's Real-Time Reserve Clearing Price for TMSR, TMNSR or TMOR shall be the Real-Time Reserve Designation weighted average of the Reserve Zone Real-Time Reserve Clearing Prices in that Load Zone for TMSR, TMNSR or TMOR, as applicable;

The Reference Load Zone is the Load Zone with the minimum, non-zero Real-Time Reserve Clearing Price for TMSR, TMNSR or TMOR, as applicable.

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Load Zone from which the External Transaction is exporting for the purpose of calculating Real-Time Reserve Charges. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

III.10.4 Forward Reserve Obligation Charges.

For each Market Participant with a Forward Reserve Obligation, the ISO will determine a Forward Reserve Obligation Charge for each hour such that a Market Participant will not receive compensation for the provision of both Real-Time Operating Reserve MWs and Forward Reserve MWs for the same reserve service.

III.10.4.1 Forward Reserve Obligation Charge Megawatts for Forward Reserve Resources.

The Forward Reserve Obligation Charge megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Forward Reserve Resource are equal to the lesser of the Forward Reserve Delivered

MW or Real-Time Reserve Designation MW (where any demand reduction portion of Real-Time Reserve Designation MW is increased by average avoided peak distribution losses).

III.10.4.2 Forward Reserve Obligation Charge Megawatts.

The Forward Reserve Obligation Charge megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Market Participant is equal to the lesser of the sum of Forward Reserve Obligation Charge megawatts for all the Reserve Resources assigned by the Market Participant, or the Final Forward Reserve Obligation

III.10.4.3 Forward Reserve Obligation Charge.

The Forward Reserve Obligation Charge will be calculated as follows:

(a) A Market Participant's Forward Reserve Obligation Charge for TMNSR in each Reserve Zone shall be equal to the Market Participant's Forward Reserve Obligation Charge megawatts for TMNSR in that Reserve Zone multiplied by the Real-Time Reserve Clearing Price for TMNSR in that Reserve Zone.

(b) A Market Participant's Forward Reserve Obligation Charge for TMOR in each Reserve Zone shall be equal to the Market Participant's Forward Reserve Obligation Charge megawatts for TMOR in that Reserve Zone multiplied by the Real-Time Reserve Clearing Price for TMOR in that Reserve Zone.

SECTION III

MARKET RULE 1

STANDARD MARKET DESIGN

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III.12.9 Tie Benefits.

III.13. Forward Capacity Market.

The ISO shall administer a forward market for capacity ("Forward Capacity Market") in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market ("Capacity Commitment Period"), the ISO shall conduct a descending clock auction ("Forward Capacity Auction") in accordance with the provisions of Section III.13.2 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 Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1. A Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (Section III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section III.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Resource, New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the financial assurance deposit described in Section III.13.1.9.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1.

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate 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) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than $200 per kilowatt of the whole resource's summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than $100 per kilowatt of the whole resource's summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.
The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output greater than 2 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, but less than or equal to the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section does not cause the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement, the Project Sponsor must submit a New Capacity Qualification Package but is not required to submit a New Capacity Show of Interest Form for the incremental amount by the New Capacity Qualification Deadline. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.3 causes the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement or MW amount approved pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), the Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.1.5. Treatment of Resources that are Partially New and Partially Existing.

For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.1.3 or Section III.13.1.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.1.6. **Treatment of Deactivated and Retired Units**.

(a) [Reserved.]

(b) 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), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline. 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), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

III.13.1.1.1.7 **Renewable Technology Resources.**

To participate in the Forward Capacity Market as a Renewable Technology Resource, a Generating Capacity Resource must satisfy the following requirements:

(a) receive an out-of-market revenue source supported by a state- or federally-regulated rate, charge or other regulated cost recovery mechanism;

(b) qualify as a renewable or alternative energy generating resource under any New England state's mandated (either by statute or regulation) renewable or alternative energy portfolio standards as in effect on January 1, 2014, or, in states without a standard, qualify under that state's renewable energy goals as a renewable resource (either by statute or regulation) as in effect on January 1,

2014. The resource must qualify as a renewable or alternative energy generating resource in the state in which it is geographically located;

(c) participate in a Forward Capacity Auction for a Capacity Commitment Period beginning on or after June 1, 2018 as a New Generating Capacity Resource pursuant to Section III.13.1.1, and;

(d) has been designated for treatment as a Renewable Technology Resource pursuant to Section III.13.1.1.2.9.

An Export De-List Bid or Administrative Export De-List Bid may not be submitted for Generating Capacity Resources that assumed a Capacity Supply Obligation by participating in a Forward Capacity Auction as a Renewable Technology Resource.

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.

For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also submit to the ISO an Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the financial assurance deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. Upon submission of the financial assurance deposit by the Project Sponsor pursuant to Section III.13.1.9.1, the resource is obligated to participate and will be included in the Forward Capacity Auction at its FCA Qualified Capacity amount at the Forward

Capacity Auction Starting Price. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, material changes (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein. The New Capacity Show of Interest Form is available on the ISO website. A New Capacity Show of Interest Form to which a material change has been made shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor's contact information; the Project Sponsor's ISO customer status; the project's expected Commercial Operation date; the project address or location, and if relevant, asset identification number; the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall have the same meaning as set forth in Schedule 22 or Schedule 23, as applicable, of Section II of the Transmission, Markets and Services Tariff. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must submit, with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall mean that: (i) the Project Sponsor is the owner in fee simple of the real property on which the project will be located; (ii) the Project Sponsor holds a valid written leasehold interest in the real property on which the project will be located; (iii) the Project Sponsor holds a valid written option, exercisable solely by the Project Sponsor or its assignee, to purchase or lease property on which the project will be located; or (iv) the Project Sponsor holds a duly executed written contract to purchase or lease the real property on which the project will be located. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits**. In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing**. In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders**. In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2.2(d) and that accounts for more than five percent of the total project cost.

(d) **Substantial Site Construction**. In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery**. In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing**. In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (d) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent Commercial Operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning**. In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation**. In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. Offer Information.

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity at or above the Economic Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity 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 the OATT.

III.13.1.1.2.2.4. Capacity Commitment Period Election.

In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) 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. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity. In addition to the information described elsewhere in this Section III.13.1.1.2.2:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource and Intermittent Settlement Only Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource or the Intermittent Settlement Only Resource.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a material change (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource's Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s), as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

(g) New Generating Capacity Resources, or portions thereof, shall not be considered to have met their Capacity Supply Obligation for the purposes of this Forward Capacity Market and shall not receive compensation if any upgrades to be completed by the Project Sponsor required to remove overlapping interconnection impacts as identified in (f) have not been completed, including, any upgrades identified in a restudy pursuant to Section 3.2.1.3 of Schedule 22 and Section 1.7.1.3 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff and, if necessary, requests for the interconnection of an Elective Transmission Upgrade, in time for the Capacity Commitment Period unless the Capacity Supply Obligation is appropriately covered.

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource’s New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

(a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;

(b) whether the critical path schedule includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and

(e) whether, in the case of an Intermittent Power Resource or Intermittent Settlement Only Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a 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.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a 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 amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. [Reserved.]

III.13.1.1.2.7. Opportunity to Consult with Project Sponsor.

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor 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 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 believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor 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.

III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

(a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;

(b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource's New Capacity Qualification Package was not accepted;

(c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);

(d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource's summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;

(e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Generating Capacity Resource; (ii) for the notification to a Conditional Qualified New Generating Capacity Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Generating Capacity Resource, the Queue Position of the Conditional Qualified New Generating Capacity Resource; and

(f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal Market Monitor's determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.1.2.9 Renewable Technology Resource Election.

A Project Sponsor or Market Participant electing Renewable Technology Resource treatment for the FCA Qualified Capacity of a New Generating Capacity Resource shall submit a Renewable Technology Resource election form no later than five Business Days after the date on which the ISO provides qualification determination notifications pursuant to Section III.13.1.1.2.8. Only the portion of the FCA Qualified Capacity of the resource that meets the requirements of Section III.13.1.1.1.7 is eligible for treatment as a Renewable Technology Resource.

Renewable Technology Resource elections may not be modified or withdrawn after the deadline for submission of the Renewable Technology Resource election form.

III.13.1.1.2.10 Determination of Renewable Technology Resource Qualified Capacity.

(a) If the total FCA Qualified Capacity of Renewable Technology Resources exceeds the cap specified in subsections (b), (c) and (d) the qualified capacity value of each resource shall be prorated by the ratio of the cap divided by the total FCA Qualified Capacity. The ISO shall notify the Project Sponsor or Market Participant, as applicable, of the Qualified Capacity value of its resource no more than three Business Days after the deadline for submitting Renewable Technology Resource elections.

(b) The cap for the Capacity Commitment Period beginning on June 1, 2018 is 200 MW.

(c) The cap for the Capacity Commitment Period beginning on June 1, 2019 is 400 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior Capacity Commitment Period.

(d) The cap for each Capacity Commitment Period beginning on or after June 1, 2020 is 600 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior two Capacity Commitment Periods.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Resource or Existing Demand Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only

Resource's net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006 summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be established pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e).

(b) The Intermittent Power Resource's or Intermittent Settlement Only Resource's summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) 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 the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.

(a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in each of the previous winter periods, or portion thereof if the

Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.

(b) The Intermittent Power Resource's and Intermittent Settlement Only Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.2(a).

(c) 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 the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the two treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) [Reserved.]

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, and if accepted by the ISO shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

The Dynamic De-List Bid Threshold beginning with the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018) shall be $3.94/kW-month. The Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Dynamic De-List Bid Threshold shall be filed with the Commission under Section 205 of the Federal Power Act prior to the Existing Capacity Qualification Deadline for the associated Forward Capacity Auction.

III.13.1.2.3.1.1. Static De-List Bids.

An Existing Generating Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation at prices at or above the Dynamic De-List Bid Threshold during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section

III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests). Static De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.2. Permanent De-List Bids.

An Existing Generating Capacity Resource seeking to specify a price below which it would not accept a Capacity Supply Obligation permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource's full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource, an Intermittent Settlement Only Resource or a Renewable Technology Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource, an Intermittent Settlement Only Resource or a Renewable Technology Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity

Commitment Period. Administrative Export De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.

A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.

The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a resource that has a Permanent De-List Bid rejected by the Internal Market Monitor, a Non-Price Retirement Request may be submitted within 14 days after the resource receives notice of the rejection or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.

III.13.1.2.3.1.5.3. Reliability Review of Non-Price Retirement Requests.

The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

III.13.1.2.3.1.5.4. Obligation to Retire.

A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5.3(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.

III.13.1.2.3.1.6. Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. Internal Market Monitor Review.

The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

(i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.

(ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive de-listing of each individual asset in preferred de-list order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of bids as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The bids of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will reject the bid as described in Section III.13.1.2.3.2.1.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

For purposes of this Section III.13.1.2.3.2, a Static De-List Bid, Permanent De-List Bid, or Export Bid shall be associated with a pivotal supplier if, using the best available estimates of FCA Qualified Capacity available at that time: (1) at the Forward Capacity Auction Starting Price, the total amount of FCA Qualified Capacity of all Existing Capacity Resources in the New England Control Area minus the Installed Capacity Requirement (net of HQICCs) is less than or equal to the greater of:

(a) the amount of FCA Qualified Capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and

(b) the amount of FCA Qualified Capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW;

or (2) where the bid is associated with a resource in an import-constrained Capacity Zone, if at the Forward Capacity Auction Starting Price, the total amount of FCA Qualified Capacity of all Existing Capacity Resources in the import-constrained Capacity Zone minus the Local Sourcing Requirement for the import-constrained Capacity Zone is less than or equal to the greater of:

(a) the amount of FCA Qualified Capacity from all Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and

(b) the amount of FCA Qualified Capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 100 MW.

In making this determination, the total amount of FCA Qualified Capacity of all Existing Capacity Resources will be reduced by an amount equal to the total of all pending Non-Price Retirement Requests and Permanent De-List Bids other than those submitted by the Lead Market Participant for the resource being evaluated, and the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource will include any capacity subject to a pending Non-Price Retirement Request or Permanent De-List Bid. The determination whether a Lead Market Participant is pivotal will be included in the qualification determination notification described in Section III.13.1.2.4. If the applicable Installed Capacity Requirement (net of HQICCs) and Local Sourcing Requirement are not finalized at the time that the Internal Market Monitor must make this determination, then the Internal Market Monitor shall use the best available estimates of those values available at that time, and shall publish those estimated values to the ISO website no later than the date that the qualification determination notifications are issued.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids the Dynamic De-List Bid Threshold, and Permanent De-List Bids Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid, each Export Bid above the Dynamic De-List Bid Threshold, and each Permanent De-List Bid above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) The Existing Generating Capacity Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); (3) reasonable risk premium assumptions (as determined pursuant to Section III.13.1.2.3.2.1.4); and (4) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). Sufficient documentation and information about each of these bid components must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments and risk premiums, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate. The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

III.13.1.2.3.2.1.1.1. Review of Permanent De-List Bids and Export Bids.

(a) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(b) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(c) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, reasonable expectations about the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.1(c), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor. The Lead Market Participant for such a resource may elect to have the ISO-determined bid entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b) by so indicating in a filing with the Commission in response to the informational filing described in Section III.13.8.1(a). Such a filing, and notification to the ISO of any such election, shall be made in accordance with the terms of Section III.13.8.1(b) and shall not limit the other rights provided under that section. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. In no case shall rejection of a de-list bid by the Internal Market Monitor restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.

(a) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

(b) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

(c) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.2(b), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor. In such a case, no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. If no such election is made, and the Existing Generating Capacity Resource is entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c), then nothing in this subsection shall restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

III.13.1.2.3.2.1.2. Net Going Forward Costs.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net going forward costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. A Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing Generating Capacity Resource's net going forward costs based on a review of the data submitted in the following formula. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{[GFC - (IMR - PER)] \times InfIndex}{(CQ_{Summer,}\ kw) \times (12, months)}$$

Where:

GFC = annual going forward costs, in dollars. These are costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

$CQ_{Summer}kW$ = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid),this value shall be calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00. As soon as practicable, the resource's total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected

InfIndex = inflation index. infIndex = $(1 + i)^4$

Where: "*i*" is the most recent reported 4- Year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.
The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.13.1.2.3.2.1.4. Risk Premium.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. This documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.13.1.2.3.2.1.2 may be included in this risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the Forward Capacity Market is consistent with the participant's corporate risk management practices.

III.13.1.2.3.2.1.5. Opportunity Costs.

To the extent that an Existing Generating Capacity Resource submitting a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, expected Capacity Performance Payments, or risk premium components of the bid, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. Administrative Export De-List Bids.

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

Age of Existing Resource (years)	**Remaining Life (years)**	**Annual Rate of Capital Cost Recovery**
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{\textit{Cost Of Capital}}{(1-(\mathbf{1}+\textit{CostOfCapital})^{-\textit{RemainingLife}})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Qualification Determination Notification for Existing Capacity.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid including a determination whether the Lead Market Participant is pivotal as described in Section III.13.1.2.3.2 and indicating whether the bid has been accepted for participation in the Forward Capacity Auction. Where a Static De-List Bid, Permanent De-List Bid, Export Bid, or Administrative Export De-List Bid is not accepted for participation in the Forward Capacity Auction as a result of the Internal Market Monitor's review pursuant to Section III.13.1.2.3.2, the notification shall include an explanation of the reasons the Existing Capacity Qualification Package was not accepted and shall include the resource's net going forward costs and opportunity costs as determined by the Internal Market Monitor. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external Demand Resource may not be an Existing Import Capacity Resource or a

New Import Capacity Resource. External nodes shall be mapped to Capacity Zones as shown in the following table:

External Node Common Name	Capacity Zone
NB-NE External Node	**Maine**
HQ Phase I/II External Node	**Rest-of-Pool**
Highgate External Node	**Rest-of-Pool**
NY-NE AC External Node	**Rest-of-Pool**
Cross Sound Cable External Node	**CT**

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control

Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. Qualified Capacity for Existing Import Capacity Resources.

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3. Qualification Process for Existing Import Capacity Resources.

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

(a) No later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting each Existing Import Capacity Resource must also submit to the ISO: (i) documentation of a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, including documentation of the MW value of the contract; or (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Existing Import Capacity Resource during the Capacity Commitment Period, together with information to establish the summer and winter ratings of the resource(s) backing the import. In either case, the Market Participant must specify the interface over which the capacity will be imported.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply. An Existing Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, Existing

Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

(c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3 for the duration of the contracts as listed. For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3, no later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3.

Contract Description	**MW**	**Contract End Date**
NYPA: NY ─ NE: CMEEC	13.2	8/31/2025
NYPA: NY ─ NE: MMWEC	53.3	8/31/2025
NYPA: NY ─ NE: Pascoag	2.3	8/31/2025
NYPA: NY─ NE: VELCO	15.3	8/31/2025
	84.1	
VJO: Highgate ─ NE	Up to 225	10/31/2016
VJO: Highgate ─ NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II ─ NE	Up to 110	10/31/2016

(d) In addition to the review described in Section III.13.1.2.3.2, the Internal Market Monitor shall review each bid from Existing Import Capacity Resources. A bid from an Existing Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.4. Definition of New Import Capacity Resource.

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

For each New Import Capacity Resource, the Market Participant submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the entire Capacity Commitment Period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New 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 (iv) documentation for system-backed import capacity that the import capacity 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. For each New Import Capacity Resource, the Market Participant must specify the interface over which the capacity will be imported. The Market Participant must indicate whether the import is associated with any investment in transmission that increases New England's import capability. If the import will be backed by a single new External Resource, the Market Participant submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the 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 New Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.

The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. 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 Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, 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 Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification 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. (3) The 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.13.1.3.5.4. Capacity Commitment Period Election.

The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall not apply. A New Import Capacity Resource may not elect to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears.

III.13.1.3.5.5. Initial Interconnection Analysis.

The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources.

For the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), the request and cost information described in Section III.13.1.1.2.2.3 and Section III.A.21.2 must be submitted to the ISO no later than November 7, 2014. In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from New Import Capacity Resources. An offer from a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity

Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5. For the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), the ISO shall, no later than December 12, 2014, send to Project Sponsors or Market Participants, as applicable, a determination regarding whether the New Import Capacity Resource is associated with a pivotal supplier as described in Section III.A.21.1.1 and the resource's New Resource Offer Floor Price as determined pursuant to Section III.A.21.2. For the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), a New Import Capacity Resource may be withdrawn (and hence not included in the Forward Capacity Auction) no later than January 16, 2015 by providing written notification of such withdrawal to the ISO. Any such withdrawal shall be irrevocable.

III.13.1.3.5.8. Rationing Election.

The rationing election described in Section III.13.1.1.2.2.3(b) shall not apply. A New Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, New Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

III.13.1.4. Demand Resources.

III.13.1.4.1. Demand Resources.

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with an early Commercial Operation Date shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2017. No resource shall be permitted to participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A

Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life. Demand 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 Resource. Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market Participant for a resource shall include the Enrolling Participant for a Demand Resource.

III.13.1.4.1.1. Existing Demand Resources.

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.

III.13.1.4.1.2. New Demand Resources.

A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.

For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources

For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.3. Special Provisions for Real-Time Emergency Generation Resources.

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to

Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.4.2. Show of Interest Form for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor's New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. Qualification Package for Existing Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. Qualification Package for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1. [Reserved.]

III.13.1.4.2.2.2. Source of Funding.

The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3. Measurement and Verification Plan.

For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4. Customer Acquisition Plan.

A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1. Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.

For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.2.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete

III.13.1.4.2.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor's ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor's program to deliver capacity to meet the Demand Resource Project Sponsor's Forward Capacity Auction obligations, and must include each customer's projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor's ability to fulfill its obligation by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource Project Sponsor shall be subject to the ISO's critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. Capacity Commitment Period Election.

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) 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. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.2.5.

III.13.1.4.2.2.6. Rationing Election.

The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.

The ISO shall review the Project Sponsor’s New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form. A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. Offers From New Demand Resources.

All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

III.13.1.4.2.5. Notification of Qualification for Demand Resources.

III.13.1.4.2.5.1. Evaluation of Demand Resource Qualification Materials.

The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

(a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;

(b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and

(e) whether the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.

For each Existing Demand Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type; and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located, and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. Notification of Qualification for New Demand Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.

For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource's summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.

For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.3. Measurement and Verification Applicable to All Demand Resources.
To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. 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.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects 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 Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the Demand Resource project's Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand 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. The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor's total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor's total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports 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 Demand Resource Project Sponsors. 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.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted 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 shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor's offer cleared. Additionally, the Updated Measurement and

Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue 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 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors 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 Demand Resource projects targeting customer facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor 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 Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently de-listed from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.

The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its

Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation, Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, 2017, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 2017, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity Commitment Periods commencing on or after June 1, 2017, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2017, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource’s Demand Reduction Value shall be calculated using the Real-Time Emeergency Generation Asset’s Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the Retail Delivery Point, the associated Real-Time Emergency Generation Resource’s Demand Reduction Value shall be calculated using the Real-Time Emergency Generation Asset’s Average Hourly Load Reduction.

For Capacity Commitment Periods commencing before June 1, 2017, the output of the generators comprising a Real-Time Emergency Generation Asset must be directly metered and reported to the ISO as a single set of interval meter data, provided that if there is no other Real-Time Emergency Generation Asset, Real-Time Demand Response Asset or other generator whose output can be controlled at the same facility, the Market Participant may instead meter the Real-Time Emergency Generation Asset at the retail delivery point. Meter data associated with the Real-Time Emergency Generation Asset shall be recorded and reported by the Market Participant to the ISO in Real-Time at an interval of five minutes.

For Capacity Commitment Periods commencing before June 1, 2017, the output of generators comprising a Real-Time Demand Response Asset located behind the retail delivery point must be directly metered and reported to the ISO in Real-Time as a single set of interval meter data at an interval of five-minutes.

III.13.1.4.3.2.1. No Performance Data to Determine Demand Reduction Values.

Should a new Demand Resource, other than a Demand Response Capacity Resource, enter service at a time such that there is no performance data for June, July, August, December or January upon which to establish summer or winter seasonal Demand Reduction Values, and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, then the summer or winter seasonal Demand Reduction Values will be the simple average of its Demand Reduction Values for those months with a Capacity Supply Obligation. For a new Demand Resource, other than a Demand Response Capacity Resource, that enters service outside of the summer DR Auditing Period or winter DR Auditing Period and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, the Demand Resource Commercial Operation Audit results shall be used in the determination of the summer or winter seasonal Demand Reduction Value.

III.13.1.4.3.3. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor 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.13.1.4.3.4. Measurement and Verification Costs.

Costs associated with measurement and verification of the Demand Resource project shall be borne by the Demand Resource Project Sponsor. Demand Resource Project Sponsors submitting application materials and Measurement and Verification Documents for review during the Forward Capacity Auction qualification process shall be subject to the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.4.4. Dispatch of Active Demand Resources During Event Hours.

III.13.1.4.4.1. Notification of Demand Resource Forecast Peak Hours.

The ISO shall issue notice to Market Participants concerning Demand Resource Forecast Peak Hours on the day before the relevant Operating Day. The notice issued pursuant to this section is for informational purposes only and shall not constitute a Dispatch Instruction.

III.13.1.4.4.2. Dispatch of Demand Resources During Real-Time Demand Resource Dispatch Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Demand Response Resources to curtail and restore loads during Real-Time Demand Resource Dispatch Hours. Dispatch Instructions shall apply to Real-Time Demand Response Resources. The amount of Demand Resources dispatched for each Real-Time Demand Resource Dispatch Hour will be the amount that the ISO determines is necessary to meet the reserve deficiency. The ISO may issue Dispatch Instructions that reduce or increase the amount dispatched in each hour.

III.13.1.4.4.3. Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Emergency Generation Resources to curtail and restore loads during Real-Time Emergency Generation Event Hours. Dispatch Instructions shall apply to specific Real-Time Emergency Generation Resources. The amount of Real-Time Emergency Generation Resources dispatched for each Real-Time Emergency Generation Event Hour will be the amount the ISO determines is necessary to meet the reserve deficiency.

III.13.1.4.5. Selection of Active Demand Resources For Dispatch.

III.13.1.4.5.1. Management of Real-Time Demand Response Assets and Real-Time Demand Response Resources.

A Market Participant must manage its Real-Time Demand Response Assets that are registered as a component of a Real-Time Demand Response Resource as of the first of a month so that the Real-Time Demand Response Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Demand Response Assets cause, or potentially cause, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to restore the loads of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Demand Response Asset or to restore the load of a dispatched Real-Time Demand Response Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the restoration of that asset. Market Participants with Real-Time Demand Response Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Demand Response Resources consisting of an aggregation of more than one Real-Time Demand Response Asset shall report the load reduction and consumption, or generator output of the resource, to the ISO as the sum of the load reduction, consumption, or generator output of the individual assets making up that resource. Real-Time Demand Response Resources shall be assigned a unique resource identification number. The load reduction and consumption, or generator output of a Real-Time Demand Response Resource is reported to the ISO as a single set of values. A Real-Time Demand Response Resource shall consist of one or more Real-Time Demand Response Assets that are located within the same Dispatch Zone.

III.13.1.4.5.2. Management of Real-Time Emergency Generation Assets and Real-Time Emergency Generation Resources.

A Market Participant must manage its Real-Time Emergency Generation Assets that are registered as a component of a Real-Time Emergency Generation Resource as of the first of a month so that the Real-Time Emergency Generation Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Emergency Generation Assets causes, or potentially causes, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to discontinue the output of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Emergency Generation Asset or to discontinue the output of a dispatched Real-Time Emergency Generation Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the discontinued output of that asset. Market Participants with Real-Time Emergency Generation Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Emergency Generation Resources consisting of an aggregation of more than one Real-Time Emergency Generation Asset shall report the generator output of the resource to the ISO as the sum of the generator outputs of the individual assets making up that resource. Real-Time Emergency Generation Resources shall be assigned a unique resource identification number. The generator output of a Real-Time Emergency Generation Resource is reported to the ISO as a single set of values. A Real-Time Emergency Generation Resource shall consist of one or more Real-Time Emergency Generation Assets that are located within the same Dispatch Zone.

III.13.1.4.5.3. [Reserved.]

III.13.1.4.6. Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at Dispatch Zones.

III.13.1.4.6.1. Establishment of Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location and dispatch of Demand Response Capacity Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources. Dispatch Zones shall not change during a Capacity Commitment Period. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.13.1.4.6.2. Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

III.13.1.4.6.2.1. Real-Time Demand Response Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Demand Response Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Demand Response Resource into one or more Real-Time Demand Response Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.6.2.2. Real-Time Emergency Generation Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Emergency Generation Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Emergency Generation Resource into one or more Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.7. [Reserved.]

III.13.1.4.8. [Reserved.]

III.13.1.4.9. Restrictions on Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Registration.

A Market Participant may not register and, if previously registered, must retire in accordance with Section III.13.1.4.9.1, a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

III.13.1.4.9.1. Requirement for Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Retirement.

A Market Participant must retire a previously registered Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of customers specified in subsections (a) or (b) of Section III.13.1.4.9 no later than 12 months from the date that the ISO receives notice that the relevant electric retail regulatory authority prohibits such customer's demand response to be bid into the ISO-administered markets or programs or May 31, 2013, whichever is later.

III.13.1.4.10. Providing Information On Demand Response Capacity, Real-Time Demand Response and Real-Time Emergency Generation Resources.

If requested by a Market Participant with a registered Load Asset, the ISO will provide the following information about end-use customers served by the Market Participant: (a) whether the end-use customer's facility is registered with the ISO as part of an asset and whether the asset is associated with a Demand Response Resource, Real-Time Demand Response Resource or Real-Time Emergency

Generation Resource, and; (b) the load reduction capability of the asset, as specified in the ISO's asset registration system, to which the end-use customer's facility is registered.

III.13.1.4.11. Assignment of Demand Assets to a Demand Resource.

The following mapping provisions apply to Demand Resources other than Demand Response Capacity Resources, the mapping for which is addressed in Appendix E to Market Rule 1.

(a) When a demand asset can be mapped to more than one Demand Resource, any demand assets shall be mapped to a commercial Demand Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period, before being mapped to a non-commercial Demand Resource or non-commercial increment of a Demand Resource.

(b) A demand asset cannot be unmapped from a Demand Resource if, following the unmapping, the sum of the audit values of the remaining demand assets that are mapped to the Demand Resource would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.2.4.5.3. Offers composed of separate resources may not be modified or withdrawn after the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Resource, April through November where the summer resource is a Demand Resource) 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 (October through May where the summer resource is not a Demand Resource, December through March where the summer resource is a Demand Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered 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 an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources 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.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource or Intermittent Settlement Only Resource. If the winter capacity of the offer composed of separate resources 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) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone.

(e) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained.

(f) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone.

(g) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource.

(h) A Renewable Technology Resource may only participate in an offer composed of separate resources if its FCA Qualified Capacity has not been prorated pursuant to Section III.13.1.1.2.10.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than 5 Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource's final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource's financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the financial assurance deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c) and, with the exception of demand programs for Self-Supplied FCA 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 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.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources 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 FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy

Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

(a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) If a Permanent De-List Bid above the Dynamic De-List Bid Threshold or a Static De-List Bid is approved by the Internal Market Monitor, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.13.1.9. Financial Assurance.

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy. The ISO and the NEPOOL Budget and Finance Subcommittee shall reconsider these financial assurance requirements no later than five years after the first Forward Capacity Auction is conducted.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Generating Capacity Resources) and New Demand Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the financial assurance deposit specified in the ISO New England Financial Assurance Policy by the Project Sponsor for a New Generating Capacity Resource or New Demand Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Resource in the Forward Capacity Auction at the starting price. If this financial assurance deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit shall be applied toward the resource’s financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit will be returned pursuant to the terms of the ISO New England Financial Assurance Policy.

III.13.1.9.2. Financial Assurance for New Generating Capacity Resources and New Demand Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource’s offer or a New Demand Resource’s offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Resource: (i) fails to provide the required financial assurance on any required date for any reason; or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4(c), it shall lose its Capacity Supply Obligation (which shall then be entered by the ISO into subsequent annual reconfiguration auctions) and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. Release of Financial Assurance.

Once a New Generating Capacity Resource or New Demand Resource achieves Commercial Operation and is tested for its capacity rating, 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 an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand 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 resulting shortfall in capacity shall then be entered by the ISO into subsequent annual reconfiguration auctions.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. Forfeit of Financial Assurance.

Where any financial assurance is forfeited pursuant to the provisions of this Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to the provisions of this Section III.13 shall be used to reduce payments incurred by load in the relevant Capacity Zone to replace that capacity.

III.13.1.9.2.4. Financial Assurance for New Import Capacity Resources.

A New Import Capacity Resource that is backed by a new External Resource shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource achieves Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. Qualification Process Cost Reimbursement Deposit.

For each New Capacity Show of Interest Form and New Demand Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below ("Qualification Process Cost Reimbursement Deposit"). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project's critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual 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. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22 or 23 of the OATT or where a resource modification does not require a revision to the Interconnection Agreement.

New Generating Resources ≥ 20 MW	**New Generating Resources < 20 MW and ≥ 2 MW**	**Imports and New Demand Resources (including Distributed Generation)**		**New Generating Resources < 2 MW**
Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources	*Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources*			
$25,000	$7,500	$1,000		$500
With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement	*With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement*			
$15,000	$6500	n/a		n/a

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for Commercial Operation, the ISO shall provide the Project Sponsor 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. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds 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, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If 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 exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO's consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
For all resources except Demand Resources, Nov. 1, 2006 through Jan. 2, 2007 For Demand Resources, Dec. 18, 2006 through Feb. 28, 2007	Apr. 30, 2007	June 15, 2007	Feb. 4, 2008	June 1, 2010
Sept. 18, 2007 through Nov. 14, 2007	Mar. 14, 2008	Apr. 29, 2008	Dec. 8, 2008	June 1, 2011
July 15, 2008 through Sep. 16, 2008	Feb. 3, 2009	Feb. 17, 2009	Oct. 5, 2009	June 1, 2012
May 15, 2009 through July 14, 2009	Dec. 1, 2009	Dec. 15, 2009	Aug. 2, 2010	June 1, 2013
Mar. 15, 2010 through May 14, 2010	Oct. 1, 2010	Oct. 15, 2010	June 6, 2011	June 1, 2014
Mar. 1, 2011 through Mar. 14, 2011	Aug. 1, 2011	Aug. 15, 2011	Apr. 2, 2012	June 1, 2015
Jan. 3, 2012 through Jan. 17, 2012	June 1, 2012	June 15, 2012	Feb. 4, 2013	June 1, 2016
Feb. 14, 2013 through Feb. 28, 2013	June 3, 2013	June 17, 2013	Feb. 3, 2014	June 1, 2017

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

(a) each Capacity Commitment Period shall begin in June;

(b) the New Capacity Show of Interest Submission Window will be in February (after the Forward Capacity Auction for the prior Capacity Commitment Period), approximately four years and three months before the beginning of the Capacity Commitment Period;

(c) the Existing Capacity Qualification Deadline will be in June just over four years before the beginning of the Capacity Commitment Period;

(d) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and

(e) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

The table below shows this generic timeline for the Capacity Commitment Period beginning in year "X", where X is any year after 2015.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
Feb. (X-4)	June (X-4)	June/July (X-4)	Feb. (X-3)	June X

III.13.1.11 Opt-Out for Resources Electing Multiple-Year Treatment.

Beginning in the qualification process for the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), any resource that had elected in a Forward Capacity

Auction prior to the ninth Forward Capacity Auction (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer cleared may, by submitting a written notification to the ISO no later than the Existing Capacity Qualification Deadline (or, in the case of the ninth Forward Capacity Auction, no later than September 19, 2014), opt-out of the remaining years of the resource's multiple-year election. A decision to so opt-out shall be irrevocable. A resource choosing to so opt-out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.

III.13.5. Bilateral Contracts in the Forward Capacity Market.

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals and Supplemental Availability 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.

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 monthly Capacity Supply Obligation Bilateral must be coterminous with a calendar month, and an annual Capacity Supply Obligation Bilateral must be coterminous with a Capacity Commitment Period.

(b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly Capacity Supply Obligation of the Capacity Transferring Resource during the period covered by the Capacity Supply Obligation Bilateral. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly 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 for the relevant time period) of the Capacity Acquiring Resource during the period 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) A Real-Time Emergency Generation Resource may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource.

(e) [Reserved.]

(f) [Reserved.]

(g) Prior to April 1, 2015, if the Capacity Acquiring Resource is an Import Capacity Resource, then the Capacity Transferring Resource must also be an Import Capacity Resource on the same external interface.

(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 Capacity Commitment Period month.

(j) A resource that has not achieved Commercial Operation by the submission deadline for a monthly Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that Capacity Commitment Period 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.

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 before or during submittal windows, as defined in the ISO New England Manuals and ISO New England Operating

Procedures. The ISO will issue a schedule of the submittal windows for annual and monthly 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 generation or Demand Response Resource outage information, and will include transmission security studies. The ISO will review all confirmed monthly Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. For a monthly Capacity Supply Obligation Bilateral, 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 review the net impact of all annual Capacity Supply Obligation Bilaterals to ensure that the regional and local adequacy and other reliability needs achieved through the Forward Capacity Auction are maintained in the Capacity Transferring Resource's Capacity Zone and the Capacity Acquiring Resource's Capacity Zone or across the external interface.

If after its review of the net impact of all annual Capacity Supply Obligation Bilaterals the ISO determines that the regional and local adequacy and other reliability needs achieved through the Forward Capacity Auction are not maintained, and for all monthly Capacity Supply Obligation Bilaterals, the 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 settlement 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 second Business Day after the end 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. Supplemental Availability Bilaterals.

A resource's availability score during a Shortage Event may be supplemented by entering into a Supplemental Availability Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. Designation of Supplemental Capacity Resources.

III.13.5.3.1.1. Eligibility.

Demand Response Capacity Resources and Generating Capacity Resources that are not Intermittent Power Resources or Settlement Only Resources may be designated as Supplemental Capacity Resources. A Generating Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource's CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales submitted in accordance with Section III.1.10.7(f) from that resource and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource. A Demand Response Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource's Qualified Capacity from the Forward Capacity Auction for the current Capacity Commitment

Period pursuant to Section III.13.1.4.1 and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource.

III.13.5.3.1.2. Designation.

The designation of a Supplemental Capacity Resource must be made by the resource's Lead Market Participant. The designation shall indicate the term for which the resource is designated as a Supplemental Capacity Resource, which shall be in Operating Day increments, no less than one Operating Day, and no greater than one calendar month. Such designation shall indicate the MW amount being designated as a Supplemental Capacity Resource, and the Capacity Zone in which the resource is located. Such designation must be submitted to the ISO no later than the deadline for the submission of Supply Offers in the Day-Ahead Energy Market for the first Operating Day of the indicated term.

III.13.5.3.1.3. ISO Review.

The ISO shall review the information provided in submission of the designation as a Supplemental Capacity Resource, and shall reject the designation for any of the hours in which any of the provisions of this Section III.13.5.3.1 are not met.

III.13.5.3.1.4. Effect of Designation.

Regardless of whether it ever becomes subject to a Supplemental Availability Bilateral as described in Section III.13.5.3.2, the portion of a resource designated as a Supplemental Capacity Resource is subject to the same energy market offer requirements applicable to a resource having a Capacity Supply Obligation as described in Sections III.13.6.1.1.1 and III.13.6.1.1.2 for Generating Capacity Resources and as described in Sections III.13.6.1.5.1. and III.13.6.1.5.2. for Demand Response Capacity Resources for the entire term indicated in the designation described in Section III.13.5.3.1.2.

III.13.5.3.2. Submission of Supplemental Availability Bilaterals.

The Lead Market Participant for a resource previously designated as a Supplemental Capacity Resource in accordance with the provisions of Section III.13.5.3.1 for a term that included a Shortage Event may submit a Supplemental Availability Bilateral to the ISO assigning all or a portion of its available capability up to its designated supplemental capacity in each hour of that Shortage Event to a Generating Capacity Resource or Demand Response Capacity Resource having a Capacity Supply Obligation during that Shortage Event ("Supplemented Capacity Resource"). No other Market Participant may submit a Supplemental Availability Bilateral. The Supplemental Capacity Resource and the Supplemented Capacity Resource must either: (i) be located in the same Reserve Zone (although in no case may a

Supplemental Capacity Resource located in an export-constrained Capacity Zone provide supplemental availability outside of that export-constrained Capacity Zone); or (ii) be located in different Reserve Zones such that direction of flow between the Supplemental Capacity Resource and the Supplemented Capacity Resource is counter to any Reserve Zone or Capacity Zone constraint. For purposes of this Section III.13.5.3.2, a Reserve Zone having a locational reserve requirement (established pursuant to Section III.9.2.2) that is less than or equal to zero shall be considered to be unconstrained with respect to the neighboring Reserve Zone. A Supplemental Capacity Resource may submit Supplemental Availability Bilaterals with multiple Supplemented Capacity Resources, but each MW of supplemental capacity may only be assigned to one Supplemented Capacity Resource. No Supplemental Capacity Resource may itself be a Supplemented Capacity Resource for an hour.

III.13.5.3.2.1. Timing.

A Supplemental Availability 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 Supplemental Availability Bilateral, a Supplemental Availability 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 Supplemental Availability Bilateral may be revised by the parties to the transaction throughout the resettlement process). A Supplemental Availability Bilateral must be confirmed by the Lead Market Participant for the Supplemented Capacity Resource no later than the same deadline that applies to submission of the Supplemental Availability Bilateral.

III.13.5.3.2.2. Application.

The submission of a Supplemental Availability Bilateral to the ISO shall include the following: (i) the resource identification number for the Supplemental Capacity Resource; (ii) the resource identification number for the Supplemented Capacity Resource; (iii) the MW amount of capacity being assigned from the Supplemental Capacity Resource to the Supplemented Capacity Resource; (iv) the term of the transaction, which shall be in hourly increments coinciding with hourly boundaries, no less than one hour, and no greater than one calendar month.

III.13.5.3.2.3. ISO Review.

The ISO shall review the information provided in submission of the Supplemental Availability Bilateral, and shall reject the Supplemental Availability Bilateral if any of the provisions of this Section III.13.5.3 are not met. The ISO shall reject the applicability of a Supplemental Availability Bilateral in any hour of a Shortage Event unless: (i) the Supplemental Capacity Resource was on-line and following ISO dispatch instructions during that hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is (a) less than or equal to the difference between the Generating Capacity Resource's Economic Maximum Limit as submitted or redeclared by the Lead Market Participant and the Supplemental Capacity Resource's Capacity Supply Obligation or (b) less than or equal to the difference between (the greater of the sum of the Real-Time Demand Reduction Obligations of the Demand Response Resources associated with the Demand Response Capacity Resource or the lesser of ((the sum of the Demand Response Baselines of the Demand Response Assets comprising the Demand Response Resources associated with the Demand Response Capacity Resourceas adjusted pursuant to Section III.8B.5, plus the Net Supply Limit of the Demand Response Resources), the Hourly Adjusted Audited Demand Reduction, or (the Maximum Reduction as submitted or redeclared by the Lead Market Participant plus the Net Supply Limit of the Demand Response Resources))), adjusted for average avoided peak transmission and distribution losses as addressed in Section III.13.7.1.5.10, and the Supplemental Capacity Resource's Capacity Supply Obligation; or (ii) the Supplemental Capacity Resource was offline for the hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is less than or equal to the difference between the sum of the Supplemental Capacity Resource's Real-Time Reserve Designations of TMNSR, TMSR and TMOR and the Supplemental Capacity Resource's Capacity Supply Obligation.

III.13.5.3.2.4. Effect of Supplemental Availability Bilateral.

A Supplemental Availability 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 Supplemental Availability Bilateral is to modify the Supplemented Capacity Resource's availability score as described in Section III.13.7.1.1.4.

III.13.6. Rights and Obligations.

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. Generating Capacity Resources.

III.13.6.1.1.1. Energy Market Offer Requirements.

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:

(a) 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

(b) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a) 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.

III.13.6.1.1.2. 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 economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.1.3. [Reserved.]

III.13.6.1.1.4. [Reserved.]

III.13.6.1.1.5. 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;

(c) 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 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.13.6.1.2. Import Capacity Resources.

III.13.6.1.2.1. Energy Market Offer Requirements.

A Market Participant must offer energy associated with an Import Capacity Resource with a Capacity Supply Obligation into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions for every hour of each Operating Day at the same external interface totaling an amount (MW) equal to the Capacity Supply Obligation unless the Import Capacity Resource is associated with an External Resource that is on an outage. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with this requirement may be subject to sanctions pursuant to Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.2 for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.

The offer requirements of Section III.13.6.1.2.1 will not apply to External Transactions associated with the VJO and NYPA Import Capacity Resources specified in Section III.13.1.3.3(c) for the duration of the contract provided the transactions are self-scheduled in both the Day-Ahead Energy Market and Real-Time Energy Market. If the energy associated with these contracts is not self-scheduled, the offer requirements and provisions of this section will apply to the applicable contract.

(a) All priced External Transactions associated with an Import Capacity Resource with a Capacity Supply Obligation must be offered each hour at or below the greater of either: (1) the offer threshold specified in Section III.13.6.1.2.1(b) for the Operating Day; (2) the offer threshold determined for the prior Operating Day; and (3) for any priced External Transactions from the New York Control Area the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface.

(b) A daily offer threshold will be determined for each Operating Day and will apply to each hour of the Operating Day. From June 1, 2010 to May 31, 2013 the daily offer threshold is equal to the product of the PER Proxy Unit heat rate as described in Section III.13.7.2.7.1.1.1(b)(iii) and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation of day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis. After May 31, 2013 the daily offer threshold is equal to the product of the applicable Forward Reserve Heat Rate as described in Section III.9.6.2 and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.

(c) Submittal of External Transactions to the Day-Ahead Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource requires submittal of matching energy transactions to the Real-Time Energy Market; the External Transactions submitted to the Real-Time Energy Market must match the External Transactions submitted to the Day-Ahead Energy Market, subject to the right to submit different prices into the Real-Time Energy Market.

(d) External Transactions submitted to the Real-Time Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource must be submitted prior to the offer submission deadline for the Day-Ahead Energy Market the day before the Operating Day for which they are intended to be scheduled.

(e) A Market Participant submitting a priced External Transaction supporting an Import Capacity Resource with a Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must link the transaction to the associated transmission reservation and NERC E-Tag no later than one hour before the operating hour in order to be eligible for scheduling in the Real-Time Energy Market. If a Market Participant does not link the transaction to the associated transmission reservation and NERC E-Tag in the Real-Time Energy Market for any hour during which the External Transaction would otherwise have been economically and reliably scheduled in the Real-Time Energy Market, the associated Import Capacity Resource shall be treated as having not delivered energy for the hour despite ISO requested dispatch under Section III.13.7.1.2 and III.13.7.2.7.2. A Market Participant submitting any other External Transaction to the Real-Time Energy Market must comply with the requirements in Section III.1.10.7(e) with respect to linking the transaction to the associated transmission reservation and NERC E-Tag.

III.13.6.1.2.2. Additional Requirements for Import Capacity Resources.

Import Capacity Resources are subject to the following additional requirements:

(a) information submittal requirements for External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals;

(b) resource backed Import Capacity Resources shall be subject to the outage requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures. Control Area backed Import Capacity Resources are not subject to such outage requirements;

(c) resource backed Import Capacity Resources are subject to the voluntary and mandatory re-scheduling of maintenance procedures outlined in the ISO New England Operating Procedures and ISO New England Manuals.

(d) at the time of submittal, each External Transaction shall reference the associated Import Capacity Resource.

III.13.6.1.3. Intermittent Power Resources.

III.13.6.1.3.1. Energy Market Offer Requirements.
Intermittent Power Resources may submit offers into the Day-Ahead Energy Market. Such resources are required to submit offers 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.

III.13.6.1.3.2. [Reserved.]

III.13.6.1.3.3. Additional Requirements for Intermittent Power Resources.
Intermittent Power Resources 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;

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.1.4.1. Energy Market Offer Requirements.

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.4.2. Additional Requirements for Settlement Only Resources.

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only 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;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.5. Demand Resources.

III.13.6.1.5.1. Energy Market Offer Requirements.

Seasonal Peak Demand Resources, On-Peak Demand Resources and Real-Time Emergency Generation Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Markets. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E.

Commencing June 1, 2017, a Market Participant with a Demand Response 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. The sum of the Demand Reduction Offers must be equal to or greater than the Demand Response 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 Demand Response 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 one of the following requirements:

(a) 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) the sum of the Demand Response Resource's Minimum Reduction Time plus the Minimum Time Between Reductions is less than or equal to 24 hours.

III.13.6.1.5.2. Requirement that Offers Reflect Accurate Demand Response Capacity Resource Operating Characteristics.

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a resource Demand Response Resources associated with a Demand Response Capacity Resource must reflect the then-known operating characteristics of the resource. Resources must re-declare to the ISO any changes to the 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 economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.5.3. Additional Requirements for Demand Resources.

Demand Resources shall comply with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals and the auditing and rating requirements as detailed in Section III.13.6.1.5.4 and the ISO New England Manuals. Demand Response Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1;

(b) 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 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.13.6.1.5.4. Demand Response Auditing.

Demand Resources shall be subject to ISO conducted audits for the purposes of:

(a) Auditing Demand Reduction Values or determining the Audited Demand Reduction for a Demand Resource;

(b) Verifying the Commercial Operation of a Demand Resource; and

(c) Verifying the Demand Reduction Value or the Audited Demand Reduction of the Demand Resource when the ISO, based on objective criteria, has determined that the Demand Reduction Value or the Audited Demand Reduction of a Demand Resource may not be credible.

New Demand Response Asset Audits shall be performed pursuant to Section III.13.6.1.5.4.8.

III.13.6.1.5.4.1. General Auditing Requirements for Demand Resources Excluding Demand Response Capacity Resources.

(a) Audits of a Demand Resource will be conducted by simultaneously evaluating the performance of each demand asset that is mapped to that Demand Resource.

(b) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Real-Time Demand Response Resources containing Real-Time Demand Response Assets that are located behind the same end-use customer meter as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource.

(c) An audit is valid beginning with the month in which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like seasonal DR Auditing Period. Additional audits performed in a month shall not replace the results of the initial audit conducted in a month and are valid on the first of the subsequent month following the audit. Audit results shall not replace a Demand Reduction Value that is based on Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours.

(d) If one or more demand assets of a Demand Resource do not have audit results at the time the Demand Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those demand assets toward the audit value of the Demand Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit provided the demand asset was available for dispatch by the ISO in that prior month, and if the demand asset was not available for dispatch in that prior month, then the 1st of the month in which the demand asset was available for dispatch.

III.13.6.1.5.4.2. General Auditing Requirements for Demand Response Capacity Resources.

(a) Audits of Demand Response Resources associated with a Demand Response Capacity Resource will be conducted by simultaneously evaluating the performance of each Demand Response Asset that is mapped to a Demand Response Resource. The Demand Response Resources associated with a Demand Response Capacity Resource are not required to be evaluated simultaneously.

(b) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Demand Response Resources containing Demand Response Assets that are located behind the same Retail Delivery Point as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource. When the output of the Real-Time Emergency Generation Asset is greater than the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of the Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Net Supply is reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset.

(c) An audit is valid beginning with the date on which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like Seasonal DR Audit period. For the Capacity Commitment Period commencing on June 1, 2017, the audit results for Demand Response Resources comprised of Demand Response Assets that were associated with a Real-Time Demand Response Resource in the prior Capacity Commitment Period shall be the sum of the audit results for those assets in the prior like Seasonal DR Audit period. When using audit results from a period prior to June 1, 2017 for those former Real-Time Demand Response Assets, the Audited Full Reduction Time shall be 30 minutes.

(d) If one or more Demand Response Assets of a Demand Response Resource do not have an Audited Demand Reduction at the time the Demand Response Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those Demand Response Assets toward the Audited Demand Reduction of the Demand Response Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit, provided the Demand Response Asset was available for dispatch by the ISO in that prior month, and if the Demand Response Asset was not available for dispatch in that prior month, then the 1st of the month in which the Demand Response Asset was available for dispatch.

III.13.6.1.5.4.3. Seasonal DR Audits.

A Seasonal DR Audit must be conducted for each Demand Resource during each seasonal DR Auditing Period.

III.13.6.1.5.4.3.1. Seasonal DR Audit Requirement.

A Market Participant shall submit each Demand Resource to an ISO initiated audit each season to verify the Demand Reduction Value or Audited Demand Reduction for the resource for one or more months of the season. The Seasonal DR Audit must be requested by the Market Participant for the Demand Resource within each Capacity Commitment Period in which the Demand Resource has a Capacity Supply Obligation. The summer DR Auditing Period begins on June 1 and ends on August 31. The winter DR Auditing Period begins on December 1 and ends on January 31. For all Demand Resources other than Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the audit results for the months of June, July, and August, and audits performed during the winter DR Auditing Period will be used to establish the audit results for the months of December and January. For Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource summer months of June, July, August, September, October, November, and the following April and May, and audits performed during the winter DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource winter months of December and the following January, February and March.

III.13.6.1.5.4.3.2. Failure to Request or Perform an Audit.

If by the 1st of August for the summer DR Auditing Period or by the 1st of January for the winter DR Auditing Period a Market Participant has not requested a Seasonal DR Audit for a Demand Resource, the Market Participant shall be deemed to have requested a Seasonal DR Audit on those respective dates. A Demand Resource that does not successfully perform a Seasonal DR Audit for a DR Auditing Period shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

III.13.6.1.5.4.3.3. Use of Event Performance Data to Satisfy Audit Requirements for Certain Resources.

A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource that has received a Dispatch Instruction in a season for 100% of its highest CSO for the current DR Auditing Period lasting at least one hour, not including the 30 minute Demand Response Resource Notification Time, may use the first 60 minute period of the event after the 30 minute Demand Response Resource Notification Time to satisfy the Seasonal DR Audit requirement for the applicable DR Auditing Period, subject to the provisions of Section III.13.6.1.5.4.1(b). A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource's audit value under this provision is based on the average load reduction or output demonstrated over the duration of the qualifying 60 minute period.

A Market Participant must request that an event be used to satisfy the Demand Resource's Seasonal DR Audit requirement or replace a currently effective audit result within seven days of the Operating Day on which the Dispatch Instruction for the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is received.

III.13.6.1.5.4.3.3.1. Demand Response Capacity Resources.

A Demand Response Capacity Resource may elect to use performance associated with a Shortage Event as defined in Section III.13.7.1.1.1 or a time period when the ISO has declared a capacity deficiency pursuant to ISO New England Operating Procedure No. 4 that occurs during a DR Auditing Period in place of requesting a Seasonal DR Audit; provided that any Demand Response Asset of a Demand Response Resource associated with the Demand Response Capacity Resource on a forced curtailment or scheduled curtailment as defined in Section III.13.7.1.5.10.2 is assessed a zero audit value.

If a Demand Response Resource associated with a Demand Response Capacity Resource does not reduce demand for some portion of the event, the audit results of its Demand Response Assets shall be set to zero. Otherwise, the Demand Response Resources associated with a Demand Response Capacity

Resource will be measured based upon their offered parameters per Section III.13.6.1.5.4.6(d), and the Audited Demand Reduction for each Demand Response Resource will be capped at the average Desired Dispatch Point for the Demand Response Resource over the audit duration by proportionally reducing each associated Demand Response Asset's audit results.

Within 7 calendar days of the event, the participant must inform the ISO that it wishes to use dispatch performance during the event to establish the Demand Response Resource's Audited Demand Reduction.

If a Shortage Event occurs before a Demand Response Resource has established an Audited Demand Reduction value and the resource was not dispatched during the Shortage Event at a level equal to its Maximum Reduction, a Market Participant may elect within seven calendar days after the event to set the Audited Demand Reduction of the Demand Response Resource equal to its CLAIM10 or CLAIM30 value at the time of the event as determined pursuant to Section III.9.5.3.

A Market Participant may elect to use performance associated with a CLAIM10 or CLAIM30 audit of a Demand Response Resource that occurs during a DR Auditing Period in place of requesting a Seasonal DR Audit of that resource provided that the audit was conducted in a manner that meets the requirements of a Seasonal DR Audit. Within seven calendar days of the CLAIM10 or CLAIM30 audit, the Market Participant must inform the ISO that it wishes to use dispatch performance during the audit to establish the Demand Response Resource's Seasonal DR Audit value.

III.13.6.1.5.4.4. Demand Resource Commercial Operation Audit.

(a) A Market Participant with a Demand Resource that has one or more increments that have not demonstrated commercial operation prior to the commencement of a Capacity Commitment Period shall perform a Demand Resource Commercial Operation Audit. The results of the Demand Resource Commercial Operation Audit shall be used to verify the commercial capacity of the Demand Resource and establish the Audited Demand Reduction of a Demand Response Resource.

(b) If a Demand Resource Commercial Operation Audit is not performed prior to the commencement of the Capacity Commitment Period, an audit must be requested in time for performance within the first month in which the Demand Resource has a Capacity Supply Obligation in the Capacity Commitment Period or the Commercial Operation Date, whichever is earlier. A Demand Resource that does not successfully perform a Demand Resource Commercial Operation Audit prior to the end of the first month in which the Demand Resource has a Capacity Supply Obligation shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

(c) A Demand Resource that fails to demonstrate through its Demand Resource Commercial Operation Audit a demand reduction in the amount of its Capacity Supply Obligation shall be subject to the provisions of Section III.13.1.9 and Section III.13.3.4.

(d) A Market Participant may request additional Demand Resource Commercial Operation Audits during a Capacity Commitment Period to verify an increase in the commercial capacity of a Demand Resource.

(e) If a Demand Resource has summer Qualified Capacity, a Demand Resource Commercial Operation Audit must be performed during the summer season (April through November) to verify the commercial capacity of the resource. A Demand Resource Commercial Operation Audit performed during the winter season (December through March) may only be used to verify the winter commercial capacity of the resource.

(f) A Demand Resource Commercial Operation Audit performed during a summer DR Auditing Period or winter DR Auditing Period may be used to satisfy the Seasonal DR Audit requirement for the same seasonal period. If a Demand Resource conducts a Demand Resource Commercial Operation Audit outside of a summer DR Auditing Period or winter DR Auditing Period, the Seasonal DR Audit requirement shall not be satisfied, however the results shall be used in the calculation of the summer Seasonal DR Audit value or winter Seasonal DR Audit value as follows:

(1) A Demand Resource Commercial Operation Audit conducted in the months of September, October, November, April, or May shall be considered a summer Seasonal DR Audit;

(2) A Demand Resource Commercial Operation Audit conducted in February or March shall be considered a winter Seasonal DR Audit.

III.13.6.1.5.4.5. Additional Audits.

The ISO may initiate an audit to verify the Demand Reduction Value or Audited Demand Reduction of a Demand Resource when an evaluation based on objective criteria indicates a Market Participant is claiming demand reductions in excess of the Demand Resource's actual capability. Such criteria include, but are not limited to:

(a) A pattern of submitting to the ISO a level of available interruption that is less than the resource's Demand Reduction Value or Audited Demand Reduction during the same time period;

(b) Actual loads for the underlying assets of the resource that, when aggregated, are below the resource's Demand Reduction Value or Audited Demand Reduction; or

(c) Failure to achieve the dispatched interruption.

The results of an additional audit shall replace the results of the last like Seasonal DR Audit or Demand Resource Commercial Operation Audit.

The ISO may perform additional audits for a Demand Resource to establish the audit results or Audited Demand Reduction and the performance of the installed measures of the demand asset or Demand Response Asset. This additional auditing may consist of two levels.

(a) Level 1 Audit: the ISO will establish the audit results by conducting a review of records of the demand asset or Demand Response Asset to verify that the reported 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 measures in the demand asset or Demand Response Asset. 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 Resource is less than or greater than its Demand Reduction Value or Audited Demand Reduction in the same period, then the Demand Reduction Value or Audited Demand Reduction shall be adjusted to the value demonstrated through the audit.

III.13.6.1.5.4.6. Audit Methodologies.

(a) For On-Peak Demand Resources, audit results shall be established based on the Average Hourly Output or Average Hourly Load Reduction in the DR Auditing Period.

(b) For Seasonal Peak Demand Resources, audit results shall be established based on Average Hourly Output or Average Hourly Load Reduction or their equivalent in the DR Auditing Period.

(c) For Real-Time Demand Response Resources and Real-Time Emergency Generation Resources, audits will be conducted via a Dispatch Instruction sent by the ISO. Audit results for a Real-Time Demand Response Resource and Real-Time Emergency Generation Resource will be based on the sum of the average load reductions or average incremental output demonstrated during the audit by each demand asset mapped to the Demand Resource.

(d) For Demand Response Resources associated with Demand Response Capacity Resources, audits will be conducted via a Dispatch Instruction. Audit results for the Demand Response Resources will be based on the sum of the average demand reductions demonstrated during the audit by each Demand Response Asset associated with the Demand Response Resource that is mapped to the Demand Response Capacity Resource using (i) each Demand Response Resource's Offered Full Reduction Time to establish the start of the audit period and (ii) the Minimum Reduction Time adjusted for ramping time as the audit duration. The Offered Full Reduction Time is the Demand Response Resource Notification Time plus the Demand Response Resource Start-Up Time plus ((the Maximum Reduction minus the Minimum Reduction) divided by the Demand Response Resource Ramp Rate). For purposes of determining the Offered Full Reduction Time, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Maximum Reduction is reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset.

III.13.6.1.5.4.7. Requesting and Performing an Audit.

(a) Seasonal DR Audits and Demand Resource Commercial Operation Audits will be performed following the request of the Market Participant. Audits will be performed within 20 Business Days of the date requested by the Market Participant. The date and time of the audit will be unannounced. An audit request may be denied by the ISO, and an audit may be rescheduled, if its performance will jeopardize the reliable operation of the electrical system.

(b) Seasonal DR Audits may be performed on different dates and at different times for Demand Response Resources associated with a Demand Response Capacity Resource if the Demand Response Resources have different offer parameters. In addition, the ISO will only schedule Demand Resource Commercial Operation Audits of a Demand Response Resource with Demand Response Assets that do not have an Audited Demand Reduction value.

(c) New Demand Response Asset Audits will be performed following the request of the Market Participant. The request for a New Demand Response Asset Audit by the Market Participant shall be made during the last seven days of the month. The audit will be performed on Business Days during the month following the date of the request by the Market Participant. The date and time of the audit will be unannounced. An audit request may be denied by the ISO, and an audit may be rescheduled, if its performance will jeopardize the reliable operation of the electrical system.

III.13.6.1.5.4.8. New Demand Response Asset Audits

A Market Participant may request a New Demand Response Asset Audit for all New Demand Response Assets that are mapped to a Demand Resource. The results of a New Demand Response Asset Audit may be used:

(a) In calculating the Seasonal DR Audit value for the Demand Resource to which the asset is mapped until the next Seasonal DR Audit for the full Demand Resource is conducted;

(b) In calculating the commercial capacity value of the Demand Resource for purposes of determining release of financial assurance pursuant to Section III.13.1.9.2.2, until the next Demand Resource Commercial Operation Audit is conducted;

(c) For determination regarding termination under Section III.13.3.4(c); and

(d) In the monthly calculation of a Demand Resource's Demand Reduction Value pursuant to Section III.13.7.1.5.7 and Section III.13.7.1.5.8.

When a New Demand Response Asset Audit is performed, the commercial capacity value and Seasonal DR Audit value of the Demand Resource to which the asset is mapped shall be updated to reflect any changes in the composition of the Demand Resource.

III.13.6.1.5.4.8.1. General Auditing Requirements for New Demand Response Assets.

(a) A New Demand Response Asset Audit will be conducted by simultaneously evaluating the performance of each New Demand Response Asset that is mapped to that Demand Resource.

(b) A New Demand Response Asset Audit is valid beginning with the month in which the audit is performed, and remains valid until the next Seasonal DR Audit is performed for a like season or until a Demand Resource Commercial Operation Audit is performed. Additional audits performed in a month shall not replace the results of the initial audit conducted in a month and are valid on the first of the month following the audit. Audit results shall not be used in the calculation of a Demand Reduction Value that is based on Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours.

III.13.6.1.5.5. Reporting of Forecast Hourly Demand Reduction.

A Market Participant with Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO a two-day forecast of each Demand Resource's Forecast Hourly Demand Reduction for each Operating Day. The Market Participant shall update its forecast, in accordance with the ISO New England Manuals and Operating Procedures, to reflect its estimate of each Demand Resource's Forecast Hourly Demand Reduction.

III.13.6.1.5.6. Reporting of Monthly Maximum Forecast Hourly Demand Reduction.

A Market Participant with Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO each month a forecast of each resource's monthly maximum Forecast Hourly Demand Reduction for each of the next 12 months.

III.13.6.2. 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.13.6.2, and shall not be subject to the requirements set forth in Section III.13.6.1 during the

Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.13.6.2.1. Generating Capacity Resources.

III.13.6.2.1.1. 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.

III.13.6.2.1.1.1. 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.13.6.2.1.1.2. Real-Time Energy Market Participation.
A Generating Capacity Resource having no 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, must Self-Schedule in order to participate 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.13.6.2.1.2. 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 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.13.6.2.2. [Reserved.]

III.13.6.2.3. Intermittent Power Resources.

III.13.6.2.3.1. 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.

III.13.6.2.3.2. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources 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.13.6.2.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.2.4.1. Energy Market Offer Requirements.

A Settlement Only Resource may not submit an offer into the Day-Ahead Energy Market or the Real-Time Energy Market.

III.13.6.2.4.2. Additional Requirements for Settlement Only Resources.

Settlement Only Resources 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;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.2.5. Demand Resources.

III.13.6.2.5.1. Energy Market Offer Requirements.

Real-Time Emergency Generation Resources, Seasonal Peak and On-Peak Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E1. A Market Participant with a Demand Response Resource associated with a Demand Response 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.

For Demand Reduction Offers made into the Day-Ahead Energy Market and Real-Time Energy Market for such Demand Response Resources, the sum of the Demand Response Resource's Minimum Reduction Time plus the Minimum Time Between Reductions must also be less than or equal to 24 hours.

III.13.6.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with a Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response 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.13.6.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with a Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response 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.13.6.2.5.2. Additional Requirements for Demand Response Capacity Resources Having No Capacity Supply Obligation.

Demand Response Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in Section III.13.6.1.5.4 and 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. Demand Response Capacity Resources having no 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.13.6.3. 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.13.6.3 and the ISO New England Manuals. Intermittent Power Resources, Settlement Only Resources, and Demand 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.

III.13.6.4. ISO Requests for Energy.

The ISO may request that a Demand Response Capacity Resource or Generating 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 Section III.13 of this Tariff by such a request to provide energy from that capacity, and shall not be subject to any availability penalties under Section III.13 of this Tariff by such a request for failure to provide energy from that capacity that is not subject to a Capacity Supply Obligation. 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.13.6.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.13.6.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

III.13.7. Performance, Payments and Charges in the FCM.

During each month within each Capacity Commitment Period ("Obligation Month"), each resource that acquired or shed a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will be subject to payments, charges, penalties and adjustments for such activity. In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month shall have their performance measured throughout the month, based on the resource's availability during any Shortage Events in the Obligation Month.

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. Performance Measures.

III.13.7.1.1. Generating Capacity Resources.

During each Capacity Commitment Period, each Generating Capacity Resource having a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will have its performance measured during each Obligation Month based on the resource's availability during any Shortage Events during the month.

III.13.7.1.1.1. Definition of Shortage Events.

(a) In all Capacity Zones, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for Ten-Minute Non-Spinning Reserves shall be a Shortage Event.

(b) Prior to June 1, 2017, in any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for the "minimum TMOR" requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement (described in Section III.2.7A(c)) when Action 2 under Operating Procedure No. 4 has also been implemented for the entire Capacity Zone shall also be a Shortage Event. Beginning on June 1, 2017, in any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for the "minimum TMOR" requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement (described in Section III.2.7A(c)) shall also be a Shortage Event.

(c) Prior to June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be Action 2 under Operating Procedure No. 4, or any Operating Procedure No. 7 event, that is declared for the entire import-constrained Capacity Zone for thirty or more contiguous minutes and that is not also declared for the entire Rest-of-Pool Capacity Zone. Beginning on June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for the local Thirty-Minute Operating Reserves requirement (described in Section III.2.7A(c)) that is declared for the entire import-constrained Capacity Zone.

(d) In all cases, to be considered discrete Shortage Events, such events must be separated by at least 2.5 hours. Events that would satisfy the definition of Shortage Events except that they are separated by less than 2.5 hours shall be considered a single Shortage Event with a duration equal to the sum of the lengths of the underlying events. There shall be no more than two Shortage Events per Capacity Zone per day. If there are more than two Shortage Events in a day, only the first two Shortage Events that occur will be recognized.

(e) For the purposes of Section III.13.7.1.1.1(d), Shortage Events that cross daily boundaries will be considered to occur on the day in which the Shortage Event was triggered. Availability during Shortage Events that cross monthly boundaries will be applied to the Obligation Month in which the Shortage Event was triggered.

III.13.7.1.1.1.A Shortage Event Availability Score.

For each Shortage Event, the ISO shall calculate a Shortage Event Availability Score for each resource, as follows: For each hour containing any portion of the Shortage Event, the ISO shall multiply the resource’s hourly availability score by the number of minutes of the Shortage Event in that hour, and then divide the product by the total number of minutes in the Shortage Event. The resulting values for each hour shall then be added together to determine the resource’s Shortage Event Availability Score.

III.13.7.1.1.2. Hourly Availability Scores.

The ISO shall calculate an availability score for each resource for each hour that contains any portion of a Shortage Event. A resource’s availability score for an hour, expressed as a percentage which may not exceed 100 percent, shall be the sum of the resource's available MW in that hour plus any adjustments pursuant to Section III.13.7.1.1.4 divided by the resource's Capacity Supply Obligation. In the event that there are no Shortage Event hours during a month, no availability penalties will be assessed.

III.13.7.1.1.3. Hourly Available MW.

A resource's available MW in each hour that contains any portion of a Shortage Event shall be determined pursuant to the provisions of this Section III.13.7.1.1.3, provided, however, that in no case shall a resource's available MW in an hour exceed that resource's CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales from that resource).

(a) For a resource that is on-line with a metered output greater than zero and following ISO dispatch instructions, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(b) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification time plus cold start time of thirty minutes or less, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(c) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification plus cold start-up time of less than or equal to 12 hours (16 hours, during the first five Capacity Commitment Periods for resources with notification plus start-up times greater than 12 hours as of June 16, 2006) and the output, up to the Capacity Supply Obligation, was competitively offered into the Energy Market (i.e., capacity from the listed portion of the resource was offered at or below the appropriate Reference Level plus applicable conduct thresholds) but was not committed by the ISO and was consequently unavailable within 30 minutes, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(d) For a resource that is off-line but not meeting the requirements of either Section III.13.7.1.1.3(b) or Section III.13.7.1.1.3(c), the available MW in an hour shall be zero.

(e) For a resource that is on-line but not able to follow ISO dispatch instructions, the available MW in an hour shall be the resource's metered output for the hour.

(f) Where a resource is not committed due to an outage or derate of transmission equipment within the New England Control Area, other than an outage or de-rate of transmission equipment that is controlled by the owner of the resource or that constitutes a radial lead to a resource in the New England Control Area (other than radial leads to Wyman 4 and Stony Brook), that resource's available MW in an hour shall not be reduced as result. Maine Independence Station shall be considered available when derated or not committed because of a transmission constraint.

(g) Where a resource is denied a self-schedule request by the ISO and therefore was not available in the Real-Time Energy Market, that resource's available MW in an hour shall not be reduced as a result.

(h) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation and cannot conduct its capability audit by the first day of the Obligation Month, that resource's available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(i) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, that resource's available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(j) Where a resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), that resource will have its hourly available MW reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

III.13.7.1.1.4. Availability Adjustments.

(a) A resource's hourly availability score may be increased using a Supplemental Availability Bilateral as described in Section III.13.5.3. Where all of the requirements of Section III.13.5.3 are met, the amount of available MW from the Supplemented Capacity Resource during each hour of the Shortage Event will be increased by the amount of supplemental capacity specified in the Supplemental Availability Bilateral, provided, however, that only available capacity above the Supplemental Capacity

Resource's Capacity Supply Obligation, if any, during each hour of the Shortage Event may be counted as supplemental capacity for the Supplemented Capacity Resource. The sum of these amounts will be counted in determining the availability score of the Supplemented Availability Resource for the Shortage Event.

(b) A resource's hourly availability score may be increased when an asset associated with the resource is on a planned outage that was approved in the ISO's annual maintenance scheduling process. Market Participants may indicate when submitting a planned outage request that the outage is to be considered exempt as described in ISO New England Operating Procedure No. 5. In such cases the associated resource's hourly available MWs may be increased by an amount up to the outage MWs requested, provided that the resource has not exceeded the maintenance allotment hour limit regarding exempt approved planned outages at the time of the Shortage Event as described in the ISO New England Manuals. In the case of a Settlement Only Resource, a planned outage scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource's hourly availability score as described in this subsection.

III.13.7.1.1.5. Poorly Performing Resources.

Prior to the Forward Capacity Auction qualification process, the ISO shall determine whether a resource meets the following two criteria: in the most recent four consecutive Capacity Commitment Periods or the most recent 4 years in which the resource assumed a Capacity Supply Obligation: (a) the resource received 3 annual availability scores of less than or equal to 40 percent; and (b) the resource has failed to be available in its entirety during ten or more Shortage Events during that same period. The annual availability score for each Capacity Commitment Period shall be equal to the average of all availability scores as calculated for each hour during each Shortage Event. If both of these criteria are met, the resource shall be considered a Poorly Performing Resource and shall not be eligible to participate in any subsequent Forward Capacity Auctions, and may not assume an obligation through the reconfiguration auctions, or Capacity Supply Obligation Bilaterals until it either achieves an availability score of 60 percent or higher in three consecutive Capacity Commitment Periods or 3 consecutive years, or demonstrates to the ISO that the reasons for the inadequate availability scores have been remedied. For the purposes of determining whether a resource is a Poorly Performing Resource, its availability score while it is de-listed shall not be considered. For the purposes of returning from poorly performing status, the ISO, at the request of the resource owner, may consider performance while de-listed, but in no case shall the ISO use non-consecutive years for evaluating a resource's performance.

III.13.7.1.2. Import Capacity.

The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as defined in Section III.13.7.1.1.1. An Import Capacity Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1, as appropriate). An Import Capacity Resource's available MW in each hour that contains any portion of a Shortage Event shall be determined as follows:

(a) Where the corresponding External Transactions are delivering energy in accordance with ISO dispatch instructions, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(b) Where the corresponding External Transactions have been offered in accordance with the provisions of Section III.13.6.1.2 and is not delivering energy during the hour because the ISO has not requested dispatch of the transaction, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(c) Where the corresponding External Transactions have not been offered in accordance with the provisions of Section III.13.6.1.2 or have been offered in accordance with the provisions of Section III.13.6.1.2 and are not delivering energy during the hour despite ISO requested dispatch of the transaction, the resource's available MW in the hour shall be zero.

(d) Where the Import Capacity Resource was offered in accordance with the provisions of Section III.13.6.1.2 but cannot make Real-Time deliveries of energy because the relevant external interface is already flowing at its Total Transfer Capability into New England in Real-Time, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

III.13.7.1.2.1. Availability Adjustments.

The hourly availability score of an Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource is on a planned outage in the same manner as described in Section III.13.7.1.1.4(b).

III.13.7.1.3. Intermittent Power Resources.

The performance measure for Intermittent Power Resources, including Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.4. Settlement Only Resources.

III.13.7.1.4.1. Non-Intermittent Settlement Only Resources.
A Non-Intermittent Settlement Only Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively. Its available MW in an hour of a Shortage Event shall be the resource's metered output for the hour.

III.13.7.1.4.2. Intermittent Settlement Only Resources.
The performance measure for Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.5. Demand Resources.

III.13.7.1.5.1. Capacity Values of Demand Resources.
The Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, multiplied by one plus the percent average avoided peak transmission and distribution losses used by the ISO in its calculations of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. Beginning with the Capacity Commitment Period starting June 1, 2012 the Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by one plus the percent average avoided peak transmission and distribution losses used to calculate the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. For the first Forward Capacity Auction, the value of the Installed Capacity Requirement

divided by the 50/50 summer system peak load forecast shall be 1.143, and one plus the percent average avoided peak transmission and distribution losses shall be 1.08.

III.13.7.1.5.1.1. Special Provisions for Demand Resources that Cleared in the First through Seventh Forward Capacity Auctions in which Project Sponsor Elected to have its Capacity Supply Obligation and Capacity Clearing Price Apply for Multiple Capacity Commitment Periods.

For a Demand Resource that cleared in the Forward Capacity auction for the Capacity Commitment Period beginning June 1, 2010 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2010, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.143 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2011, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.161 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for any of the Capacity Commitment Periods beginning June 1, 2012 through the Capacity Commitment Period beginning in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply in a future Capacity Commitment Period, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.08. This special provision shall cease to apply once the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.2. Capacity Values of Certain Distributed Generation.

For those Distributed Generation resource assets that are capable of generating energy in excess of the facility load and capable of delivering the excess generation to the power grid, if across Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, as appropriate, a Distributed Generation resource asset's monthly average hourly output is greater than the monthly average hourly load of the end-use customer to which the resource is directly connected, the Capacity Value of the portion of output exceeding the customer's load for the month will be the Demand Reduction Value for that portion of the output. No average avoided peak transmission and distribution losses shall be applied to Net Supply associated with a Demand Response Asset, Demand Response Resource, or Demand Response Capacity Resource.

III.13.7.1.5.3. Demand Reduction Values.

A Demand Reduction Value is a quantity of reduced demand produced by a Demand Resource and is calculated pursuant to Section III.13.7.1.5.4, III.13.7.1.5.5, III.13.7.1.5.6, III.13.7.1.5.7 and III.13.7.1.5.8.

III.13.7.1.5.4. Calculation of Demand Reduction Values for On-Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of On-Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource On-Peak Hours in the month.

III.13.7.1.5.4.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. The summer seasonal Demand Reduction Value shall apply to the months of September, October, November, April and May.

III.13.7.1.5.4.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. The winter seasonal Demand Reduction Value shall apply to the months of February and March.

III.13.7.1.5.5. Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource Seasonal Peak Hours in the month. If there are no Demand Resource Seasonal Peak Hours in the months of July, August, or January, the Demand

Reduction Value for those months shall be equal to: (i) the Demand Reduction Value established for the previous month if the previous month's Demand Reduction Value was calculated using Seasonal Peak Hours or (ii) the Seasonal DR Audit results if the Demand Reduction Value for the previous month was not calculated using Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) where there was no audit conducted in the month, the applicable previous seasonal Demand Reduction Value.

III.13.7.1.5.5.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. This summer seasonal Demand Reduction Value will apply to the months of September, October, November, April and May.

III.13.7.1.5.5.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. This winter seasonal Demand Reduction Value will apply to the months of February and March.

III.13.7.1.5.6. [Reserved.]

III.13.7.1.5.6.1. [Reserved.]

III.13.7.1.5.6.2. [Reserved.]

III.13.7.1.5.7. Demand Reduction Values for Real-Time Demand Response Resources.
Demand Reduction Values are determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Demand Response Resource is the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of July, August, or January, the Demand Reduction Value of that resource for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous month's Demand Reduction Value was calculated using Real-Time Demand Response Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Demand Response Event Hours. If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of June or December the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month.

III.13.7.1.5.7.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of a Real-Time Demand Response Resource for September, October, November, April and May shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Values in the most recent months of June, July and August and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of a Real-Time Demand Response Resource for February and March shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of December and January if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Value in the most recent months of December and January and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Demand Response Resource receiving a Dispatch Instruction for a Real-Time Demand Response Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Demand Response Resource’s Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the

Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Demand Response Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.7.3.1. Determination of the Hourly Real-Time Demand Response Resource Deviation.

An Hourly Real-Time Demand Response Resource Deviation shall be calculated for each Real-Time Demand Response Resource as the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Demand Response Event Hour. The calculation of the Hourly Real-Time Demand Response Resource Deviation shall be determined in a manner that reflects that Real-Time Demand Response Resources are allowed 30 minutes from the beginning of the first Real-Time Demand Response Event Hour in consecutive Real-Time Demand Response Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in the Dispatch Instruction when such resources are dispatched in response to Real-Time Demand Resource Dispatch Hours. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Demand Response Resource Deviation is greater than zero in any Real-Time Demand Response Event Hour, the Hourly Real-Time Demand Response Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Load Zone in the hour or, starting on June 1, 2011, in the same Dispatch Zone in the hour.

III.13.7.1.5.8. Demand Reduction Values for Real-Time Emergency Generation Resources. Demand Reduction Values shall be determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Emergency Generation Resource shall be the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous months Demand Reduction Value was calculated using Real-Time Emergency Generation Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resouce in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Emergency Generation Event Hours. If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resouce in that month.

III.13.7.1.5.8.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value for the months of September, October, November, April and May shall be equal to the simple average of the Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of September, October, November, April or May, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8, during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value for the months of February and March shall be equal to the simple average of the Demand Reduction Values in the most recent months of December and January if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of February or March, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8 during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Emergency Generation Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Emergency Generation Resource receiving a Dispatch Instruction for a Real-Time Emergency Generation Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Emergency Generation Resource's Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Emergency Generation Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.8.3.1. Determination of the Hourly Real-Time Emergency Generation Resource Deviation.

An Hourly Real-Time Emergency Generation Resource Deviation shall be calculated for each Real-Time Emergency Generation Resource as the difference between the Average Hourly Output or Average Hourly Load Reduction of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Emergency Generation Event Hour. The calculation of the Hourly Real-Time Emergency Generation Resource Deviation shall be determined in a manner that reflects that Real-Time Emergency Generation Resources are allowed 30 minutes from the beginning of the first Real-Time Emergency Generation Event Hour in consecutive Real-Time Emergency Generation Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in a Dispatch Instruction. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency

Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Emergency Generation Resource Deviation is greater than zero in any Real-Time Emergency Generation Event Hour, the Hourly Real-Time Emergency Generation Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Dispatch Zone in the hour.

III.13.7.1.5.9. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources and Real-Time Emergency Generation Resources Starting with the Capacity Commitment Period beginning June 1, 2012.

Starting with the Capacity Commitment Period beginning June 1, 2012, the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3, which is equal to the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, shall be eliminated from the determination of Hourly Calculated Demand Resource Performance Values, with the exception of Demand Resources that cleared in the Forward Capacity Auctions for the Capacity Commitment Periods beginning June 1, 2010 and June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared. For Demand Resources with such multi-year Capacity Supply Obligations the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3 shall continue to apply until the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.10. Demand Response Capacity Resources.

The performance of a Demand Response Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as defined in Section III.13.7.1.1.1. A Demand Response Capacity Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1). For the portion associated with the ability to reduce load at the Retail Delivery Point, availability for Demand Response Capacity Resources would be adjusted for average avoided peak transmission and distribution losses as described in Section III.13.7.1.5.1 and Section III.13.7.1.5.1.1. For the portion associated with the ability to provide Net Supply, availability for Demand Response Capacity Resources would not be adjusted for average avoided peak transmission and distribution losses.

III.13.7.1.5.10.1 Hourly Available MW.

A Demand Response Capacity Resource's available MW in each hour that contains any portion of a Shortage Event shall be determined based upon the sum of its associated Demand Response Resources as follows, provided, that in no case shall a Demand Response Capacity Resource's available MW in an hour exceed that resource's Qualified Capacity from the Forward Capacity Auction for the current Capacity Commitment Period per Section III.13.1.4.1. For purposes of the following calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the calculated demand reduction of the Demand Response Asset measured at the Retail Delivery Point shall be reduced by the Real-Time Emergency Generation Asset's output.

(a) For a Demand Response Resource that produces a demand reduction and is following Dispatch Instructions where the Desired Dispatch Point for the Demand Response Resource is less than the Maximum Reduction and greater than or equal to the Minimum Reduction, the available MW in an hour shall be the greater of (i) the resource's Real-Time Demand Reduction Obligation and (ii) the lesser of the resource's Demand Response Baseline as adjusted pursuant to Section III.8B.5 plus the Net Supply Limit, the resource's Hourly Adjusted Audited Demand Reduction, or the resource's Maximum Reduction as submitted or redeclared by the Lead Market Participant for the resource.

(b) For a Demand Response Resource that produces a demand reduction and is following Dispatch Instructions where the Desired Dispatch Point for the Demand Response Resource is equal to the Maximum Reduction or the Desired Dispatch Point for the Demand Response Resource is less than the Minimum Reduction, the available MW in an hour shall be the resource's Real-Time Demand Reduction Obligation plus any associated Net Supply.

(c) For a Demand Response Resource that has produced a demand reduction but is not following Dispatch Instructions where the Real-Time Demand Reduction Obligation is less than the Desired Dispatch Point for the Demand Response Resource, the available MW in an hour shall be the resource's Real-Time Demand Reduction Obligation for the hour.

(d) For a Demand Response Resource that has produced a demand reduction but is not following Dispatch Instructions where the Real-Time Demand Reduction Obligation is greater than the Desired Dispatch Point for the Demand Response Resource, the available MW in an hour shall be the lesser of the resource's Real-Time Demand Reduction Obligation and Hourly Adjusted Audited Demand Reduction for the hour.

(e) For a Demand Response Resource that is not producing a demand reduction, is available for dispatch and is able to respond to Dispatch Instructions, and has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) and an Audited Full Reduction Time (adjusted for the Maximum Reduction) of thirty minutes or less, the available MW in an hour shall be the lesser of the resource's (i) Maximum Reduction, as submitted or redeclared by the Lead Market Participant, (ii) Actual Load plus the Net Supply Limit or (iii) Hourly Adjusted Audited Demand Reduction.

(f) For a Demand Response Resource that is not producing a demand reduction, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction as submitted or redeclared by the Lead Market Participant) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than thirty minutes and less than or equal to 12 hours, the available MW shall be zero unless the duration of the Shortage Event exceeds the Audited Full Reduction Time (adjusted for the Maximum Reduction) and Offered Full Reduction Time (adjusted for the Audited Demand Reduction), in which case the available MW in an hour shall be the lesser of (i) the resource's Maximum Reduction, as submitted or redeclared by the Lead Market Participant, (ii) the resource's Actual Load plus its Net Supply Limit or (iii) the resource's Hourly Adjusted Audited Demand Reduction time weighted to reflect the portion of the hour in which the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time exceeded the Shortage Event duration.

(g) For a Demand Response Resource that (i) is not producing a demand reduction, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than 12 hours or (ii) is unavailable to reduce demand, the available MW shall be zero.

III.13.7.1.5.10.1.1 Adjusted Audited Demand Reduction.

A Demand Response Resource's Adjusted Audited Demand Reduction shall be determined as follows. For purposes of these calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Maximum Reduction shall be reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset:

(a) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) equal to its Audited Full Reduction Time (adjusted for the Maximum Reduction) shall have its Adjusted Audited Demand Reduction set equal to the resource's Audited Demand Reduction.

(b) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than its Audited Full Reduction Time (adjusted for the Maximum Reduction) shall have its Adjusted Audited Demand Reduction calculated as:

((the Audited Full Reduction Time adjusted for the Maximum Reduction) divided by (the Offered Full Reduction Time adjusted for the Audited Demand Reduction)) multiplied by the lesser of the Audited Demand Reduction or Maximum Reduction as submitted or redeclared by the Lead Market Participant.

(c) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) less than its Audited Full Reduction Time (adjusted for the Maximum Reduction) shall have its Adjusted Audited Demand Reduction calculated as:

((the Offered Full Reduction Time adjusted for the Audited Demand Reduction) divided by (the Audited Full Reduction Time adjusted for the Maximum Reduction)) multiplied by the lesser of the Audited Demand Reduction or Maximum Reduction as submitted or redeclared by the Lead Market Participant.

III.13.7.1.5.10.1.2 Hourly Adjusted Audited Demand Reduction.

The Hourly Adjusted Audited Demand Reduction shall be calculated as the time weighted average of the Adjusted Audited Demand Reduction and Audited Demand Reduction for the period the resource was dispatched.

III.13.7.1.5.10.2 Availability Adjustments.

The hourly availability score of a Demand Response Capacity Resource shall be increased in the same manner as described in Section III.13.7.1.1.4(a). The hourly availability score of a Demand Response Capacity Resource comprised of an aggregation of one or more Demand Response Resources shall be adjusted as described in Section III.13.7.1.1.4(b). In the case of Demand Response Resources comprised of an aggregation of one or more Demand Response Assets with a demand reduction and any Net Supply of less than 5 MW achieved by the asset in the most recent seasonal audit of the associated Demand Response Resource, a planned outage of the equipment used to produce the demand reduction scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource's hourly availability score as described in Section III.13.7.1.1.4(b).

In addition, the hourly availability score of a Demand Response Capacity Resource shall be increased as described in this subsection:

(a) A Demand Response Capacity Resource's hourly availability score shall be increased, subject to verification by the ISO, when one or more Demand Response Assets of a Demand Response Resource associated with the Demand Response Capacity Resource is on a forced curtailment or scheduled curtailment.

(i) A forced curtailment can be submitted to the ISO as described in the ISO New England Manuals for any reductions in demand that occur as a result of actions outside the control of the Demand Response Asset that is subject to the forced curtailment. The forced curtailment can be submitted or revised during the resettlement process and cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response Resource.

(ii) A scheduled curtailment must be submitted to the ISO at least seven calendar days ahead of the start of the curtailment to be eligible for an adjustment for any reductions in load that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Demand Response Assets with a Maximum Interruptible Capacity of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The scheduled curtailment cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response Resource. Scheduled curtailments must be a minimum of a single calendar day, and shall not exceed a total of 14 calendar days per Capacity Commitment Period.

(b) The sum of the availability adjustments for an hour may not exceed:

(i) for a Demand Response Resource that has received a Dispatch Instruction to reduce its demand, the lesser of (x) the resource's Demand Response Baseline as adjusted pursuant to Section III.8B.5 and (y) Audited Demand Reduction adjusted down by the greater of (1) the Maximum Reduction, as submitted or redeclared by the Lead Market Participant, or (2) Real-Time Demand Reduction Obligation. For purposes of this calculation, when the output of a Real-Time Emergency Generation Asset at the same location exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point, any Net Supply and the Maximum Reduction of the Demand Response Asset shall be reduced by the difference between the Real-Time Emergency Generation Asset's output and adjusted Demand Response Baseline of the Demand Response Asset.

(ii) for a Demand Response Resource that has not received a Dispatch Instruction to reduce its demand, the lesser of (i) the resource's Actual Load plus Net Supply Limit, or (ii) the Audited Demand Reduction adjusted down by (the Maximum Reduction, as submitted or redeclared by the Lead Market Participant.

III.13.7.1.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources are subject to the availability penalties and credits as defined by their resource type.

III.13.7.2. Payments and Charges to Resources.

Resources acquiring or shedding a Capacity Supply Obligation shall be subject to payments and charges in accordance with this Section III.13.7.2. Such resources will also be subject to adjustments as detailed in Section III.13.7.2.7.

III.13.7.2.1. Generating Capacity Resources.

III.13.7.2.1.1. Monthly Capacity Payments.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

(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 (or in the case described in Section III.13.7.1.1.3(i), the lesser of the resource's Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted pursuant to Section III.13.2.7.3(b) and 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 (the "FCA Payment"). 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 four 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.

III.13.7.2.2. Import Capacity.

Import Capacity Resources shall receive monthly capacity payments utilizing the same methodology as that used for Generating Capacity Resources set forth in Section III.13.7.2.1.

III.13.7.2.2.A. 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 (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

> 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.13.7.3.1.

III.13.7.2.3. Intermittent Power Resources.

An Intermittent Power Resource shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section 13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Power Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.4. Settlement Only Resources.

III.13.7.2.4.1. Non-Intermittent Settlement Only Resources.

Non-Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1.

III.13.7.2.4.2. Intermittent Settlement Only Resources.

Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Settlement Only Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.5. Demand Resources.

III.13.7.2.5.1. Monthly Capacity Payments for All Resources Except Real-Time Emergency Generation Resources.

For all Demand Resources except for Real-Time Emergency Generation Resources, the monthly payment shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1.

III.13.7.2.5.2. Monthly Capacity Payments for Real-Time Emergency Generation Resources.

For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f).

III.13.7.2.5.3. Energy Settlement for Real-Time Demand Response Resources

A Market Participant with Real-Time Demand Response Assets associated with a Real-Time Demand Response Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E1.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Demand Response Resource is located. The demand reduction paid or charged shall be net of the Real-Time Demand Reduction Obligation of Real-Time Demand Response Assets that are part of the Real-Time Demand Response Resource that received payment pursuant to Sections III.E1.9.2.1 or III.E1.9.2.2 for the same dispatch or audit period. Demand reductions eligible for payments or charges pursuant to this section shall be those produced during Real-Time Demand Response Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4. Energy Settlement for Real-Time Emergency Generation Resources

A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions or generator output, adjusted as described in Section III.E1.8.3 or III.13.7.2.5.4.1 and for the percent average avoided peak distribution losses for the portion of the asset reducing demand, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing prior to June 1, 2017, and at the Real-Time LMP for the Dispatch Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing on or after June 1, 2017. Demand reductions or generator output eligible for payments or charges pursuant to this section shall be those produced during Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4.1 Adjustment for Net Supply From Real-Time Emergency Generation Assets.
For Capacity Commitment Periods commencing on or after June 1, 2017, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the demand reduction measured at the Retail Delivery Point is first credited to the output of the Real-Time Emergency Generation Asset starting with the Net Supply amount, and any remaining demand reduction is credited to the Demand Response Asset. The Net Supply amount shall not be multiplied by one plus the average avoided peak distribution losses. The demand reduction amount shall be multiplied by one plus the average avoided peak distribution losses.

III.13.7.2.6. Self-Supplied FCA Resources.
Self-Supplied FCA Resources shall not receive monthly capacity payments for the portion of the resource designated as a Self-Supplied FCA Resource. Charges to load associated with Self-Supplied FCA Resources are calculated pursuant to Section III.13.7.3.

III.13.7.2.7. Adjustments to Monthly Capacity Payments.
Monthly capacity payments to resources with a Capacity Supply Obligation as of the beginning of the Obligation Month will be adjusted as described in Section III.13.7.2.7.1.

III.13.7.2.7.1. Adjustments to Monthly Capacity Payments of Generating Capacity Resources.

III.13.7.2.7.1.1. Peak Energy Rents.

Payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents (“PER”) calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone.

III.13.7.2.7.1.1.1. Hourly PER Calculations.

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

Hourly PER($/kW) = [(LMP - Strike Price) * [Scaling Factor] * [Availability Factor]

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.2.7.1.1.2. Monthly PER Application.

(a) The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as follows:

PER Adjustment = the minimum of: (i) the PER cap or (ii) the Average Monthly PER x PER Capacity Supply Obligation.

Where the PER cap for each resource equals the FCA Payment, plus the product of the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same Capacity Commitment Period multiplied by the Capacity Clearing Price applicable to that resource's location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-

Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation calculation.

(b) PER shall be deducted from capacity payments independently of availability penalties.

(c) FCA Payment minus PER may not be negative for any month.

III.13.7.2.7.1.2. Availability Penalties.

Availability penalties shall be assessed for each resource with a Capacity Supply Obligation as of the beginning of the Obligation Month. The penalty will be based on the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b) or as described in Section III.13.2.8) in the Capacity Zone in which the resource is located for the relevant Capacity Commitment Period, regardless of whether the resource assumed the Capacity Supply Obligation through a Forward Capacity Auction, a reconfiguration auction, or a Capacity Supply Obligation Bilateral.

For capacity resources that are partially or fully unavailable during a Shortage Event:

(a) Penalties shall be determined and assessed on a resource-specific basis. Penalties shall be calculated for each Shortage Event during an Obligation Month and assessed on a monthly basis, subject to the availability penalty caps outlined in Section III.13.7.2.7.1.3.

(b) The penalty per resource for each Shortage Event shall be equal to:

Penalty = [Resource's Annualized FCA Payment]*PF*[1 – Shortage Event Availability Score]

Where:

Annualized FCA Payment = the relevant Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) multiplied by the resource's Capacity Supply Obligation as of the beginning of the Obligation Month multiplied by 12.

PF = .05 for Shortage Events of 5 hours or less. PF is increased by .01 for each additional hour above 5 hours.

III.13.7.2.7.1.3. Availability Penalty Caps.

The following caps will apply to the total availability penalties assessed to a resource. If a resource with a Capacity Supply Obligation sheds or acquires an obligation outside the relevant Obligation Month, the Annualized FCA Payment shall not be prorated. Caps are resource-specific and partial year assumption or transfer of a Capacity Supply Obligation through Capacity Supply Obligation Bilaterals or reconfiguration auctions does not affect the application of the cap to each resource independently.

(a) **Per Day**. In no case shall the total penalties for all Shortage Events in an Operating Day exceed 10 percent of a resource's Annualized FCA Payment for that Capacity Commitment Period.

(b) **Per Month**. The sum of a resource's penalties arising from unavailability during an Obligation Month may not exceed two and one-half times the Annualized FCA Payment, divided by twelve, for that Obligation Month. The sum of a resource's penalties arising from unavailability due to a single outage of four days or less but spanning two calendar months may not exceed two and one-half times the average of the Annualized FCA Payments, divided by twelve, for both months.

(c) **Per Capacity Commitment Period**. In determining the availability penalties for the Obligation Month, a resource's cumulative availability penalties for a Capacity Commitment Period may not exceed its Annualized FCA Payment (less PER adjustments) for that Capacity Commitment Period.

III.13.7.2.7.1.4. Availability Credits for Capacity Demand Response Capacity Resources, Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources.

On a monthly basis, penalties received from unavailable resources shall be redistributed to Demand Response Capacity Resources, Generating Capacity Resources and Import Capacity Resources with Capacity Supply Obligations and to designated Supplemental Capacity Resources without a Capacity Supply Obligation that have a valid Supplemental Availability Bilateral (pursuant to Section III.13.5.3.2) that were available (pursuant to Section III.13.7.1.1.3, Section III.13.7.1.5.10.1) in the respective hours on a Capacity Zone basis as follows: For each Obligation Month, the penalties assessed for the Shortage Events during the month will be credited to those resources identified above that were available, in whole or in part, during the Shortage Events, pro-rata by hourly available MW in the relevant Capacity Zones.

Self-Supplied FCA Resources shall be eligible to receive their pro rata share of availability penalties paid by other capacity resources.

III.13.7.2.7.2. Import Capacity.

In addition to the adjustment in this section, Import Capacity Resources shall also be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.2.1. External Transaction Offer and Delivery Performance Adjustments.

In the event that the conditions in Section III.13.6.1.2.1 are not met in any hour of an Operating Day, the Import Capacity Resource will be subject to the following:

(a) If in any hour of an Operating Day a priced External Transaction associated with an Import Capacity Resource with a Capacity Supply Obligation is offered above both the offer threshold for the Operating Day and the offer threshold of the prior Operating Day, and for any priced External Transactions from the New York Control Area also is offered above the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the Import Capacity Resource's Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

(b) For every hour of an Operating Day that the total amount offered from all External Transactions associated with an Import Capacity Resource is less than the Import Capacity Resource's Capacity Supply Obligation, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the Capacity Supply Obligation and the total amount of energy offered for that hour and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month. For each Operating Day only the greater of the total penalties in either the Day-Ahead Energy Market or Real-Time Energy Market will be assessed. For the purposes of this section the total energy offered will be adjusted in accordance with Section III.13.7.1.1.4(b) for any amount that was unavailable due to an outage approved in the ISO's annual maintenance scheduling process.

(c) Except as specified in Section III.13.7.2.7.2.2, for every hour the total energy from an External Transaction associated with an Import Capacity Resource delivered in real-time to the New England Control Area is less than the energy requested, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the quantity requested and the quantity delivered and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month.

Any External Transaction associated with an Import Capacity Resource that is determined to be in economic merit during the next-hour scheduling process will be considered a requested transaction and the ISO may request all or a portion of each transaction.

A Market Participant's total penalty amount for a single Operating Day for each Import Capacity Resource shall be no more than the product of the Import Capacity Resource's Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

Each Obligation Month the penalty amounts from all Market Participants with Import Capacity Resources will be allocated to all Market Participants based on their pro-rata share of Capacity Load Obligation within each Capacity Zone in the Obligation Month, with each Capacity Zone allocated an amount based on the pro-rata share of total capacity credits within each Capacity Zone.

III.13.7.2.7.2.2. Exceptions.

a) No penalty will be assessed if the applicable external interface is fully loaded and the energy from an External Transaction that would otherwise be requested cannot flow. If the transfer capability of the applicable external interface is zero in the import direction it will be considered fully loaded for the purpose of this section.

b) No penalty will be assessed if the delivered energy from a priced External Transaction associated with the New York Control Area is less than requested when the Real-Time Energy Market price at the source location (NYISO Location-Based Marginal Price) is higher than the Real-Time LMP at the associated External Node, provided that Operating Procedure No. 4 has not been declared due to a system-wide capacity deficiency.

c) No penalty will be assessed during periods when the ISO has taken action to reduce import transactions due to a Minimum Generation Emergency condition or due to ramping constraints.

d) No penalty will be assessed on the affected external interface during periods when minimum-flow or directional-flow constraints have occurred, when the ISO was unable to utilize the automated check-out processes for the external interface, or when in-hour curtailments have occurred.

III.13.7.2.7.3. Intermittent Power Resources.

Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.4. Settlement Only Resources.

III.13.7.2.7.4.1. Non-Intermittent Settlement Only Resources.

Non-Intermittent Settlement Only Resources are subject to the same PER adjustments and availability penalties as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.4.2. Intermittent Settlement Only Resources.

Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.5. Demand Resources.

Demand Response Capacity Resources shall be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.5.1. Calculation of Monthly Capacity Variances.

For each month, the Monthly Capacity Variance of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be calculated by subtracting the Demand Resource’s Capacity Supply Obligation for the month from the Demand Resource’s monthly Capacity Value. If a Demand Resource’s Monthly Capacity Variance is zero, the Demand Resource will not be subject to Demand Resource Performance Penalties or Demand Resource Performance Incentives.

III.13.7.2.7.5.2. Negative Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Demand Resource's Monthly Capacity Variance is a negative value, the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be subject to a Demand Resource Performance Penalty equal to the absolute value of the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f). If a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a negative value, the Demand Resource Performance Penalty for such a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be set according to the Capacity Clearing Price applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource (as adjusted pursuant to Section III.13.2.7.3(b)), 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 applicable to the Demand Resource for the particular Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Demand Resource for the particular Capacity Commitment Period.

III.13.7.2.7.5.3. Positive Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource's Monthly Capacity Variance is a positive value, then the Demand Resource shall be eligible to receive a Demand Resource Performance Incentive based on the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period, or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the

Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone. If a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a positive value, then the Demand Resource Performance Incentive for such a Demand Resource shall be set according to the Capacity Clearing Price applicable to the Demand Resource for the particular Capacity Commitment Period (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource for the particulate Capacity Commitment Period in effect as of December 31 of the year preceding the Capacity Commitment Period, provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone.

III.13.7.2.7.5.4. Determination of Net Demand Resource Performance Penalties and Demand Resource Performance Incentives.

Demand Resource Performance Penalties and Demand Resource Performance Incentives shall be determined for each Capacity Zone as follows: if the sum of the Demand Resource Performance Penalties in a month in a Capacity Zone is less than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone, then the total amount of Demand Resource Performance Penalties shall be paid on a pro-rata basis, based on the non-prorated Demand Resource Performance Incentives of each Demand Resource with a positive Monthly Capacity Variance. The total amount of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total amount of the Demand Resource Performance Penalties in the same month in that Capacity Zone.

The total of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total of the Demand Resource Performance Penalties in the same month in that Capacity Zone. If the total Demand Resource Performance Penalties in a month in a Capacity Zone exceeds the total Demand Resource Performance Incentives in the same month in that Capacity Zone, the difference shall not be collected from load serving entities in that Capacity Zone (the ultimate purchaser of capacity).

**III.13.7.2.7.6.		Self-Supplied FCA Resources.**

Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied, but shall be subject to the availability penalties and caps applicable to their resource types.

**III.13.7.3.		Charges to Market Participants with Capacity Load Obligations.**

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.13.7.2 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals), less PER adjustments for resources in the zone as defined in Section 13.7.2.7.1.1, adjusted for any Demand Resource Performance Penalties in excess of Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.4, and including any applicable export charges or credits as determined pursuant to Section III.13.7.2.2.A 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 satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.

**III.13.7.3.1.		Calculation of Capacity Requirement and Capacity Load Obligation.**

The ISO shall assign each load serving entity a Capacity Requirement 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 Capacity Requirement 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) 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 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. The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with pumping of pumped hydro generators, if the resource was pumping; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; net load associated with an Alternative Technology Regulation Resource while providing Regulation and transmission losses associated with delivery of energy over the Control Area tie lines.

A load serving entity's Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the Capacity Zone's Capacity Requirement as calculated above and (ii) the ratio of the sum of the load serving entity's annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period to 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 prior to the start of the Capacity Commitment Period.

A load serving entity's Capacity Load Obligation shall be its Capacity Requirement, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supply FCA Resource designations. A Capacity Load Obligation can be a positive or negative value. A Market Participant that is not a load serving entity shall have a Capacity Load Obligation equal to the net obligation resulting from Capacity Load Obligation Bilaterals, HQICC, and Self-Supply FCA Resource designations.

A Demand Resource's Demand Reduction Value will not be reconstituted into the load of the Demand Resource for the purpose of determining the Capacity Requirement for the load associated with the Demand Resource.

III.13.7.3.1.1. HQICC Used in the Calculation of Capacity Requirements.

In order to treat HQICCs as a load reduction, each holder of HQICCs shall have its Capacity Requirement in the Capacity Zone in which the HQ Phase I/II external node is located as specified in Section III.13.1.3 adjusted by its share of the total monthly HQICC amount.

III.13.7.3.1.2. Charges Associated with Self-Supplied FCA Resources.

The capacity associated with a Self-Supplied FCA Resource shall be treated as a credit toward the Capacity Load Obligation of the load serving entity so designated by such resources as described in Section III.13.1.6. The amount of Self-Supplied FCA Resources shall be determined pursuant to Section III.13.1.6.

III.13.7.3.1.3. 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.13.7.3.2. Excess Revenues.

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.13.7.3.3.

III.13.7.3.3. Capacity Transfer Rights.

III.13.7.3.3.1. Definition and Payments to Holders of Capacity Transfer Rights.

The ISO shall create Capacity Transfer Rights ("CTRs") 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.13.7.3.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER and for Demand Resource Performance Penalties net of Demand Resource Performance Incentives.

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-Supply 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-Supply FCA Resources.

The value of CTRs specifically allocated pursuant to Sections III.13.7.3.3.2(c), III.13.7.3.3.4, and III.13.7.3.3.6 shall be calculated as the product of: (i) the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) for 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. The value of the specifically allocated CTRs will be deducted from the associated Capacity Zone’s portion of the CTR fund. The balance of the CTR fund will then be allocated to the load serving entities as set forth in Section III.13.7.3.3.2.

III.13.7.3.3.2. Allocation of Capacity Transfer Rights.

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.13.7.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 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.13.7.3.3.6 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.

(c) **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. Each municipal utility entitlement holder of a resource constructed as a Pool-Planned Unit in Maine shall receive specifically allocated CTRs across the Maine Export Interface equal to the applicable seasonal claimed capability of its ownership entitlements in such unit as described in Section III.13.7.3.3.6. The balance of the CTR fund associated with the Maine Export Interface shall be allocated to load serving entities with a Capacity Load Obligation on the import-constrained side of the Maine Export Interface.

III.13.7.3.3.3. Allocations of CTRs Resulting From Revised Capacity Zones.
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.13.7.3.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 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.13.7.3.3.4. 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.13.7.3.3.2.

(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.13.7.3.3.2.

III.13.7.3.3.5. [Reserved.]

III.13.7.3.3.6. Specifically Allocated CTRs for Pool Planned Units.

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 an initial allocation of CTRs equal to the applicable seasonal claimed capability of the ownership entitlements in such unit. Municipal utility 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	Summer (MW)	Winter (MW)
Nominal Summer (MW)	1155.001	1244.275	104.000	100.000	104.000	67.400	65.300	586.725		
Nominal Winter (MW)	1155.481	1244.275	119.000	116.000	119.000	87.400	85.300	608.575		
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%	58.26	63.73
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%	5.04	5.55
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%	2.93	2.37
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%	15.49	15.64
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%	10.40	11.07
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%	57.69	60.26
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%	82.98	92.77
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%	30.53	32.64
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%	4.53	5.22
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%	4.71	5.35
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	7.63	7.63
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%	5.81	6.61
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%	26.40	30.36
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%	17.01	19.33
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%	15.34	16.63
Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%	24.05	24.12

Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%	10.70	12.28
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%	11.67	13.63
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%	36.93	42.17
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%	21.48	24.45
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%	25.58	29.49
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.33	1.33
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%	4.82	5.53
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%	24.33	26.23
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	10.89	10.90
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%	6.60	7.38
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.25	1.25
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%	10.67	12.27
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%	6.97	7.99
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%	10.18	11.69
Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%	67.51	77.27

This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs 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.

III.13.7.3.4. 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 charge; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund; and (d) any applicable export charges.

SECTION III

MARKET RULE 1

APPENDIX E1

DEMAND RESPONSE

Appendix E1 applies to Capacity Commitment Periods commencing prior to June 1, 2017.

APPENDIX E1

DEMAND RESPONSE

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Appendix E1 applies to Capacity Commitment Periods commencing prior to June 1, 2017.

APPENDIX E1
DEMAND RESPONSE

1. Demand Response Registration

Appendix E1 applies to Capacity Commitment Periods commencing prior to June 1, 2017.

A Market Participant may register a Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis to provide demand reductions during hours ending 0800 through 1800 on non-Demand Response Holiday weekdays subject to the following conditions:

(a) the asset is able to produce at least 100 kW of demand reduction, and;

(b) the metering and communication equipment associated with the asset meets the requirements specified in Section III.E1.2.

A Real-Time Demand Response Asset may consist of an aggregation of multiple end-use metered customers.

1.1 Registration Parameters

During the registration process, Market Participants must submit the following information for each Real-Time Demand Response Asset:

(a) Maximum Interruptible Capacity;

(b) Maximum Load, and;

(c) Maximum Generation, for Real-Time Demand Response Assets that are comprised of Distributed Generation.

1.2 Restrictions on Real-Time Demand Response Asset Registration

A Market Participant may not register and must retire if previously registered a Real-Time Demand Response Asset that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

A Market Participant may not register an existing Generator Asset as a Real-Time Demand Response Asset for the purpose of submitting Demand Reduction Offers.

2. Metering and Communication

2.1 Interval Metering and Telemetry Requirements

The actual metered demand of each individual end-use customer facility that comprises a Real-Time Demand Response Asset must be measured using interval meters located at the individual end-use customer's retail delivery point and shall be reported to the ISO at an interval of five minutes. Actual metered demand submitted to the ISO shall not include average avoided peak distribution losses.

Interval meters required pursuant to Section III.E1.2.1 must meet the following requirements:

(a) the interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes;

(b) if the interval meter is the same meter used by the distribution company for billing purposes, the meter is a revenue-quality meter that is accurate within ± 0.5%, and;

(c) if the interval meter is not the same meter used by the distribution company for billing purposes, the interval meter is either a revenue-quality meter that is accurate within ± 0.5% or a non-revenue-quality meter with an overall accuracy of ± 2.0%. For each non-revenue-quality meter used, the Market Participant must, during the registration process, submit certification from the meter manufacturer that the interval meter being used meets the ± 2.0% accuracy threshold, and shall specify accuracy for the following parameters:

i. current measurement;

ii. voltage measurement;

iii. A/D conversion, and;

iv. calibration.

2.2 Meter Testing

All interval meters must be periodically tested and calibrated.

Market Participants must conduct periodic meter data validation checks.

Market Participants must repair or replace meters that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters and meter data communication systems.

2.3 Auditing

The ISO may, for a Real-Time Demand Response Asset, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and measurement equipment, and witness the demand reduction activities of any facility associated with the asset.

Market Participants must make retail billing meter data from the Host Participant for the facilities associated with a Real-Time Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing, and certifying the metering, data recording and measurement equipment of Real-Time Demand Response Assets.

2.4 Communication/Telemetry

Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facilities comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area. If one or more generators whose output can be controlled is located behind the retail delivery point of the Real Time Demand Response Asset, other than emergency generators that cannot operate synchronized to the electrical grid, then the Market Participant must also submit to the ISO in Real-Time a single set of interval meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

3. Demand Reduction Offers

3.1 Required Demand Reduction Offer Parameters

Market Participants must submit a Demand Reduction Offer for each Real-Time Demand Response Asset that meets the requirements of this section in order to be eligible for a demand reduction payment.

A Demand Reduction Offer must be equal to or greater than the Demand Reduction Threshold Price in effect on the day the Demand Reduction Offer is made.

Demand Reduction Offers reflect the amount of demand reduction offered at the retail delivery point excluding transmission and distribution losses.

A Demand Reduction Offer shall consist of a single offer price in $/MWh (less than or equal to $1000/MWh) and a single demand reduction amount (in MW to the nearest 0.1 MW) that shall apply to hours ending 0800 through 1800 in the Operating Day.

A Market Participant may submit a single Demand Reduction Offer for each of its Real-Time Demand Response Assets for each Operating Day that is a non-Demand Response Holiday weekday.

Demand Reduction Offers for the following Operating Day must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the Operating Day and may not be changed thereafter.

The minimum Demand Reduction Offer amount for each Real-Time Demand Response Asset is 100 kW.

The maximum Demand Reduction Offer amount for each Real-Time Demand Response Asset cannot exceed the asset's Maximum Interruptible Capacity.

Market Participants are prohibited from submitting a Demand Reduction Offer for a Real-Time Demand Response Asset for an Operating Day with a scheduled curtailment, or for an Operating Day with a known forced curtailment. If an unanticipated forced curtailment has occurred, Market Participants are prohibited from submitting a Demand Reduction Offer for the affected Real-Time Demand Response Asset for any subsequent Operating Days until the forced curtailment is over and electrical service to the asset has been restored.

3.2 Optional Demand Reduction Offer Parameters

A Demand Reduction Offer may specify a minimum interruption duration of one to four hours. If a Market Participant does not specify a minimum interruption duration in its Demand Reduction Offer, the minimum interruption duration shall be one hour.

A Demand Reduction Offer may specify a curtailment initiation price (in $ per interruption). If a Market Participant does not specify a curtailment initiation price, the curtailment initiation price shall be $0.

A Demand Reduction Offer must meet the following minimum and maximum price requirements:

(a) The offer price not including the curtailment initiation price shall be greater than or equal to the Demand Reduction Threshold Price; and

(b) The offer cost of the Demand Reduction Offer, which shall include the curtailment initiation price, shall be less than or equal to $1000/MWh. The offer cost shall be computed as follows: offer cost = offer price + [curtailment initiation price/(minimum interruption duration x bid amount (MW))].

4. Day-Ahead Clearing, Scheduling and Notification

Demand Reduction Offers are cleared after the Day-Ahead Energy Market results are determined. Demand Reduction Offers are cleared by comparing the Demand Reduction Offer to the hourly Day-Ahead LMPs for the Load Zone in which the Real-Time Demand Response Asset is located. A Demand Reduction Offer associated with a Real-Time Demand Response Asset will clear in one or more hours of the Operating Day if the sum of the hourly Day-Ahead LMP times the Demand Reduction Offer amount in the cleared hours of the Operating Day is greater than or equal to the sum of the curtailment initiation price for the Operating Day and the sum of the Demand Reduction Offer price times the Demand Reduction Offer amount in the cleared hours of the Operating Day.

The ISO will provide Market Participants with demand curtailment schedules for Real-Time Demand Response Assets based on cleared Demand Reduction Offers.

The demand curtailment schedule shall reflect demand reductions (MW) at the Real-Time Demand Response Asset's retail delivery point.

5. Real-Time Scheduling of Demand Reductions

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for the next Operating Day pursuant to Section III.E1.4. If a Market Participant's Demand Reduction Offer is not cleared Day-Ahead to reduce demand in an hourly time interval for the next Operating Day, the Market Participant may initiate a Real-Time demand reduction by reducing demand when the offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which a Real-Time Demand Response Asset is located.

A Market Participant will not receive a Dispatch Instruction in Real-Time for a Real-Time Demand Response Asset.

5.1 Requirements for Demand Reductions of 5 MW and Above

A Market Participant with a Real-Time Demand Response Asset that has submitted a Demand Reduction Offer for the Operating Day, must request permission from the ISO prior to reducing demand in an amount greater than or equal to 5 MW during a 60 minute period, unless the asset was dispatched or audited pursuant to Section III.13. Permission must be requested not less than 15 minutes and not greater than 60 minutes before the start of the demand reduction. The ISO may approve or deny the requested interruption based on the impact of the interruption on system reliability.

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data 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:

i. 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.

ii. An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer block.

iii. 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.

iv. 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 demand response exceeds the cost to load associated with compensating demand response.

v. The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} \times \frac{FPI_c}{FPI_h}$$

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 resulting 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 preceding month in advance of the Demand Reduction Threshold Price's effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Real-Time Demand Response Assets located anywhere within the New England Control Area.

7. Demand Response Baselines

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8A prior to submitting a Demand Reduction Offer for a Real-Time Demand Response Asset.

A Market Participant shall take no actions to establish a Demand Response Baseline or affect a Demand Response Baseline adjustment that results in a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers absent demand reduction payments.

For Real-Time Demand Response Assets comprised of Distributed Generation, a Market Participant shall take no actions to establish a Demand Response Baseline that results in a Demand Response Baseline that reduces the expected output levels of its generation absent demand reduction payments.

8. Real-Time Demand Reduction Obligations

8.1 Real-Time Demand Reduction of Assets Without Generation

The Real-Time demand reduction amount of a Real-Time Demand Response Asset is equal to the difference between its Demand Response Baseline adjusted pursuant to Section III.8A.4 and the asset's Real-Time metered demand, during the intervals that the Real-Time Demand Response Asset was scheduled Day-Ahead by the ISO to reduce demand or was otherwise eligible to receive payment for a demand reduction in Real-Time. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered demand is greater than its adjusted Demand Response Baseline.

8.2 Real-Time Demand Reduction of Assets With Generation

To the extent a generator is located behind the retail delivery point of an individual end-use customer facility that comprises a Real-Time Demand Response Asset, the metered output of the generator in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline. The Real-Time demand reduction amount achieved by the individual end-use customer facility that comprises a Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval minus the sum of the metered demand measured at the retail delivery point and the output of all of the generators located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of all of the generators is greater than its adjusted Demand Response Baseline.

If a Real-Time Demand Response Asset is comprised of a Distributed Generation asset located behind the retail delivery point of an individual end-use customer facility, the interval metered output of the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be used to determine its Demand Response Baseline. The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be equal to the asset's incremental output in each five-minute interval relative to its Demand Response Baseline in the same intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered output is less than its Demand Response Baseline.

8.2.1 Real-Time Demand Reduction of Assets With Generation But With No Other Real-Time Demand Response Asset at that Location

For a Real-Time Demand Response Asset located at a retail delivery point with no other Real-Time Demand Response Assets at or behind the same retail delivery point, the metered output of any Real-Time Emergency Generation Assets in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline.

The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval, calculated pursuant to Section III.8A.4.4, minus the sum of the metered demand measured at the retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of any Real-Time Emergency Generation Assets is greater than its adjusted Demand Response Baseline.

8.3 Treatment of Net Supply

If the metered amount measured at the retail delivery point reflects net energy supply during intervals in which Real-Time Demand Response Assets and/or Real-Time Emergency Generation Assets behind the retail delivery point had positive Real-Time demand reductions, then the amount of net energy supplied in an interval with a positive Real-Time demand reduction shall be subtracted from the Real-Time demand reduction amount in the same interval of each Real-Time Demand Response Asset and/or Real-Time Emergency Generation Asset behind that retail delivery point on a *pro rata* basis. The adjustment for net energy supply shall not result in a negative Real-Time demand reduction amount.

8.4 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Real-Time Demand Response Asset is equal to its Real-Time demand reduction amount adjusted for net supply (limited to 200% of the associated Demand Reduction Offer amount) multiplied by one plus the percent average avoided peak distribution losses.

9. Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Real-Time Demand Response Asset will be paid for its Day-Ahead Demand – Reduction Obligation multiplied by the Day-Ahead LMP for the Load Zone within which the Real-Time Demand Response Asset is located.

9.2 Real-Time Settlement

9.2.1. Real-Time Demand Response Assets with Cleared Demand Reduction Offers

A Market Participant with a Real-Time Demand Response Asset will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the final hourly Real-Time LMP for the Load Zone within which the Real-Time Demand Response Asset is located. The payment for the amount by which the Real-Time Demand Reduction Obligation exceeds the Day-Ahead Demand Reduction Obligation in an hour shall be set to zero if the provisional Real-Time LMP for that hour is less than the Demand Reduction Threshold Price.

A Market Participant will not be charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E1.5.1.

9.2.2. Real-Time Demand Response Assets without Cleared Demand Reduction Offers

If the Demand Reduction Offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which the Real-Time Demand Response Asset is located, the Market Participant will be paid the final hourly Real-Time LMP multiplied by its Real-Time Demand Reduction Obligation.

A Market Participant will not be charged pursuant to Section III.E1.9.2.2 if:

(a) a Demand Reduction Offer does not clear Day-Ahead pursuant to Section III.E1.4, and;

(b) the Real-Time Demand Response Asset produces a negative Real-Time demand reduction amount.

A Market Participant will not be paid for a Real-Time Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E1.5.1.

9.3 Cost Allocation

Payments and charges pursuant to this section will be allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes or incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

10. Average Distribution Losses

For purposes of Section III.E1, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

SECTION III

MARKET RULE 1

APPENDIX E2

DEMAND RESPONSE

Appendix E2 applies to Capacity Commitment Periods commencing on or after June 1, 2017.

APPENDIX E2

DEMAND RESPONSE

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Appendix E2 applies to Capacity Commitment Periods commencing on or after June 1, 2017.

APPENDIX E2
DEMAND RESPONSE

Appendix E2 applies to Capacity Commitment Periods commencing on or after June 1, 2017.

1. Demand Response Registration

1.1 Demand Response Resource Registration

A Market Participant may register a Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis and providing Operating Reserve subject to the following conditions:

(a) each Demand Response Resource must be a single Demand Response Asset or an aggregation of Demand Response Assets located within the same Dispatch Zone and Reserve Zone;
(b) each Demand Response Resource must be able to produce at least 100 kW of demand reduction;
(c) the Market Participant must comply with ISO required auditing and testing requirements; and
(d) the Market Participant must indicate whether it intends to maintain CLAIM10 or CLAIM30 capability for the Demand Response Resource.

A Market Participant may not register a Real-Time Emergency Generation Resource, an On-Peak Demand Resource, a Seasonal Peak Demand Resource or a Dispatchable Asset Related Demand to participate as a Demand Response Resource in the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant may not register a Generator Asset as a Demand Response Asset for the purpose of submitting Demand Reduction Offers. A Market Participant may not register a Demand Response Asset at the same Retail Delivery Point as an existing Generator Asset, and may not register a Generator Asset at the same Retail Delivery Point as an existing Demand Response Asset; provided that this provision shall not apply if the Generator Asset is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

1.2 Demand Response Capacity Resource Registration

A Market Participant may register a Demand Response Capacity Resource subject to the following conditions:

(a) each Demand Response Capacity Resource must have mapped to it at least one Demand Response Resource within the same Dispatch Zone in order to comply with the energy market offer requirements in Section III.13.6.1.5; and

(b) a Demand Response Resource cannot be mapped to a Demand Response Capacity Resource, or maintain the mapping to a Demand Response Capacity Resource, if the Demand Response Resource violates the mapping provisions in Section III.E2.1.4(c).

1.3 Demand Response Asset Registration

A Market Participant may register a Demand Response Asset subject to the following conditions:

(a) Unless it meets the conditions for aggregation in sub-section (b) below, a Demand Response Asset must have a defined, single Retail Delivery Point and be registered at a single Node.

(b) A Demand Response Asset may be the aggregate demand reduction capabilityof multiple end-use customers from multiple delivery points within a single Dispatch Zone and Reserve Zone if (i) the demand reduction from each Retail Delivery Point in the aggregation is less than 10 kW, and (ii) the demand at the multiple Retail Delivery Points satisfy the criteria for a homogenous population. A Demand Response Asset that meets these conditions for aggregation must be registered at a single Dispatch Zone and Reserve Zone rather than at a single Node.

(c) No more than one Demand Response Asset may be located at a single Retail Delivery Point.

(d) Each Demand Response Asset must be mapped to a Demand Response Resource.

(e) Each Demand Response Asset must be able to produce at least 10 kW of demand reduction.

(f) A Demand Response Asset with a registered Maximum Interruptible Capacity equal to or greater than 5 MW from the same Retail Delivery Point must be registered as a single Demand Response Resource at a Node. The evaluation of whether a Demand Response Asset's Maximum Interruptible Capacity is equal to or greater than 5 MW shall account for the most recent seasonal audit results for the assets.

(g) The metering and communication equipment associated with each Demand Response Asset must meet the requirements in Section III.E2.2.

During the registration process, Market Participants must submit the following for each Demand Response Asset:

(a) Maximum Interruptible Capacity;

(b) Maximum Load;

(c) Maximum Generation, for Demand Response Assets that are comprised of Distributed Generation;

(d) For a Demand Response Asset capable of producing Net Supply, the Maximum Net Supply permitted under the asset's interconnection agreement; and

(e) Retail account number and meter number for the end-use customer.

1.4 Restrictions on Demand Response Resource Registration

A Market Participant may not register and must retire if previously registered a Demand Response Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

(c) The Maximum Interruptible Capacity adjusted for the Audited Demand Reduction of each Demand Response Resource registered by a Market Participant within a single Dispatch Zone and Reserve Zone must be at least 1 MW before the Market Participant registers a new Demand Response Resource within that same Dispatch Zone and Reserve Zone. This restriction shall not apply if either:

(i) all Demand Response Assets registered by the Market Participant in the Dispatch Zone and Reserve Zone are mapped to a Demand Response Resource mapped to a Demand Response Capacity Resource and the Market Participant wants to register a Demand Response Resource that is not mapped to a Demand Response Capacity Resource; or

(ii) all Demand Response Assets registered by the Market Participant in the Dispatch Zone and Reserve Zone are mapped to a Demand Response Resource not mapped to a Demand Response Capacity Resource and the Market Participant wants to register a Demand Response Resource that is mapped to a Demand Response Capacity Resource.

(d) In the event the Audited Demand Reductions of two or more Demand Response Resources registered by a Market Participant within a single Dispatch Zone and Reserve Zone are less than 1 MW following an audit, Demand Response Asset mapping for that Market Participant shall be adjusted if doing so decreases the number of Demand Response Resources within that Dispatch Zone and Reserve Zone.

1.5 Restrictions on Demand Response Asset Mapping

Demand Response Assets may be un-mapped from a Demand Response Resource for re-mapping to another Demand Response Resource, or un-mapped without re-mapping, subject to the following conditions:

(a) A Demand Response Asset cannot be unmapped from a Demand Response Resource that is mapped to a Demand Response Capacity Resource if, following the un-mapping, the sum of the demand reductions of the remaining Demand Response Assets that are associated with the Demand Response Capacity Resource, as reflected in the most recent seasonal audit for that resource, would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

(b) When a Demand Response Asset can be mapped to more than one Demand Response Resource that is mapped to a Demand Response Capacity Resource, a Demand Response Asset shall be mapped to a Demand Response Resource associated with a Demand Response Capacity Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period before being mapped to a Demand Response Resource associated with a non-commercial Demand Response Capacity Resource or non-commercial increment of a Demand Response Capacity Resource.

(c) A Demand Response Asset may be re-mapped to another Demand Response Resource only if the Audited Full Reduction Time of the asset's new Demand Response Resource, adjusted for the Audited Demand Reduction of the asset's current Demand Response Resource, is equal to or greater than the Audited Full Reduction Time of the Demand Response Resource from which the Demand Response Asset is being un-mapped.

(d) If a Demand Response Asset is re-mapped to a Demand Response Resource, and the Audited Full Reduction Time of the Demand Response Resource to which the asset is being mapped, adjusted for the Audited Demand Reduction of the Demand Response Resource from which the asset is being mapped, is less than the Audited Full Reduction Time of the Demand Response Resource from which the asset is being mapped, the Demand Response Asset audit value will be set to zero.

2. Metering and Communication

2.1 Revenue Quality Interval Metering

The metered demand used for settlement purposes of each individual end-use customer facility that comprises a Demand Response Asset must be measured using interval meters located at the individual end-use customer's Retail Delivery Point and shall be reported to the ISO at an interval of five minutes. Metered demand data submitted to the ISO shall not include average avoided peak distribution losses.

The interval meters required pursuant to Section III.E2.2.1 must meet the following requirements:

(a) The interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes;

(b) The interval meter can be the same revenue-quality meter used by the distribution company for billing purposes; and

(c) If the interval meter is not the same revenue-quality meter used by the distribution company for billing purposes, the Market Participant must validate and provide documentation to the ISO that the difference between the values recorded by the Market Participant's meter in each interval and the value recorded by the distribution company's billing meter in the same interval is within ± 2.0%; provided that, if accurate interval data from the distribution company are not available, the Market Participant shall validate that the difference between the sum of the values recorded by the Market Participant's meter and the sum of the values recorded by the distribution company's billing meter over the same time period is within ± 2.0%; and further provided that the Market Participant specifies the meter manufacturer and model, and the accuracy for the following parameters:

    i. current measurement;
    ii. voltage measurement;
    iii. A/D conversion; and
    iv. calibration.

(d) The Market Participant shall provide documentation to the ISO of any inaccuracies found in distribution company meter data and of any communications with the distribution company to address the meter data inaccuracies.

2.2 Communication/Telemetry

Market Participants must report in Real-Time to the ISO a single set of telemetry data for each individual end-use customer facility that comprises a Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of the Demand Response Asset as measured at the Retail Delivery Point, and shall be reported to the ISO every five minutes. For a Demand Response Resource to provide Ten Minute Spinning Reserve or Ten Minute Non-Spinning Reserve, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

The Market Participant must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions.

If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of telemetry data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

The telemetry measurement device used to measure the real-time demand and any Net Supply pursuant to Section III.E2.2.2 must have an overall accuracy of ± 2.0%. If the Market Participant is not using the meter used by the distribution company for billing purposes to obtain the real-time telemetry, then the Market Participant must specify the device manufacturer and model, and submit certification from the measurement device manufacturer that the device being used meets the ± 2.0% accuracy threshold, and shall specify the accuracy for the following parameters:

i. current measurement;
ii. voltage measurement;
iii. A/D conversion; and
iv. calibration.

2.3 Testing of Meters and Telemetry Measurement Devices

All interval meters and telemetry measurement devices must be periodically tested and calibrated.

Market Participants must conduct periodic meter and telemetry data validation checks.

Market Participants must repair or replace meters or telemetry measurement devices that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters, telemetry measurement devices, and data communication systems.

2.4 Auditing

The ISO may, for Demand Response Resources, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset.

Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing and certifying the metering, data recording and telemetry measurement equipment of Demand Response Assets.

3. Day-Ahead Energy Market Demand Reduction Offers

Market Participants must submit a Demand Reduction Offer for each Demand Response Resource that meets the requirements of this section in order to be eligible for a payment for a demand reduction.

The Market Participant's Demand Reduction Offer for a Demand Response Resource must satisfy the following conditions:

(a) Demand Reduction Offers must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the applicable Operating Day.

(b) The Market Participant can submit up to 10 monotonically increasing price/demand reduction amount pairs for each Operating Day. The demand reduction amount shall not include an adjustment for average avoided peak transmission and distribution losses.

(c) The minimum amount for each price/demand reduction amount pair of a Demand Reduction Offer is 100 kW.

(d) The sum of all price/demand reduction amount pairs for a Demand Reduction Offer cannot exceed the sum of the Maximum Interruptible Capacities of the resource's Demand Response Assets.

(e) The minimum Demand Reduction Offer price must be equal to or greater than the Demand Reduction Threshold Price in effect for the day the Demand Reduction Offer is submitted.

(f) The maximum Demand Reduction Offer price must be less than or equal to the Energy Offer Cap.

Market Participants may not Self-Schedule interruptions in the Day-Ahead Energy Market.

3.1 Required Demand Reduction Offer Parameters

The Market Participant shall provide the following hourly values in its Demand Reduction Offer. The Market Participant shall maintain up-to-date values for each of these parameters prior to and throughout the Operating Day:

(a) Available or Unavailable;

(b) Minimum Reduction (MW), and;

(c) Maximum Reduction (MW).

3.2 Optional Demand Reduction Offer Parameters

The Market Participant may also specify the following in its Demand Reduction Offer:

(a) Interruption Cost ($)

(b) Minimum Reduction Time (Hrs)

(c) Minimum Time Between Reductions (Hrs)

(d) Demand Response Resource Start-Up Time (Hrs)

(e) Demand Response Resource Notification Time (Hrs)

(f) Demand Response Resource Ramp Rate (MW/min)

(g) Offered CLAIM10 (MW)

(h) Offered CLAIM30 (MW)

4. Real-Time Energy Market Demand Reduction Offers

During the Re-Offer Period, Market Participants may submit revisions to the price or demand reduction amount parameters of a Demand Reduction Offer. Demand Response Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices.

Revisions to Demand Reduction Offers during the Re-Offer Period are subject to the following conditions that apply to Day-Ahead Demand Reduction Offers under Section III.E2.3: limitation to 10 monotonically increasing price/demand reduction amount pairs, minimum amount, maximum amount, minimum price and maximum price.

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for that Operating Day pursuant to Section III.E2.5 or modified during the Re-Offer Period.

No changes will be allowed to the Demand Reduction Offer after the close of the Re-Offer Period. Market Participants may not Self-Schedule interruptions in the Real-Time Energy Market.

5. Scheduling and Dispatching

The ISO shall schedule in the Day-Ahead Energy Market and schedule and dispatch in the Real-Time Energy Market the Demand Response Resource as specified in Section III.1.7.6(a).

At the conclusion of the Day-Ahead Energy Market clearing, the ISO will provide Market Participants with Day-Ahead demand reduction schedules for Demand Response Resources reflecting demand reduction amounts that do not include average avoided peak transmission and distribution losses for each hour of the following Operating Day.

During the Operating Day, the ISO will issue Dispatch Instructions to the Market Participant specifying the expected demand reduction amount that does not include average avoided peak transmission and distribution losses from their Demand Response Resource and the Dispatch Rate.

A Market Participant must notify the ISO, as soon as practicable, of a facility or generator shutdown or equipment outage (including partial outages) that reduces the Demand Response Resource's ability to achieve the demand reduction reflected in the Demand Reduction Offer for an Operating Day.

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data 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 demand response exceeds the cost to load associated with compensating demand response.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th}\text{Ã—}\frac{FPI_c}{FPI_h}$$

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 resulting 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 preceding month in advance of the Demand Reduction Threshold Price’s effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Demand Response Resources located anywhere within the New England Control Area.

7. Real-Time Demand Reduction Obligation

A Demand Response Resource’s Real-Time Demand Reduction Obligation will be calculated for each dispatch interval in which the Demand Response Resource receives a Dispatch Instruction to reduce demand.

7.1 Real-Time Demand Reductions

The Real-Time demand reduction in a dispatch interval is the difference between the adjusted Demand Response Baseline, further adjusted for any metered output for a Real-Time Emergency Generation Asset located at the same Retail Delivery Point, and the metered demand for each Demand Response Asset associated with the Demand Response Resource.

If a Market Participant receives a Dispatch Instruction for a Demand Response Resource to reduce demand in a dispatch interval by zero MW, then in calculating the Real-Time Demand Reduction Obligation of the Demand Response Resource the Real-Time demand reductions of the Demand Response Assets comprising the resource shall be equal to zero for that dispatch interval.

7.2 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Demand Response Resource is the sum of the hourly integrated Real-Time demand reduction amounts of the Demand Response Assets comprising the Demand Response Resource, multiplied by one plus the percent average avoided peak distribution losses, except that any Net Supply produced by the Demand Response Assets comprising the Demand Response Resource will not be adjusted by average avoided peak distribution losses.

If a Market Participant fails to comply with the metering and communication requirements in Section III.E2.2 for a Demand Response Resource for any period of time, then the Real-Time Demand Reduction Obligation shall be zero for that period of time.

8. Demand Response Resource Baseline

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8B prior to submitting a Demand Reduction Offer for a Demand Response Resource, and must comply with the requirements for maintaining and resetting the Demand Response Baseline as set forth in Section III.8B.

A Market Participant shall not take actions to create or maintain a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers in the absence of demand reduction payments.

9. Energy Market Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Demand Response Resource will be paid for its Day-Ahead Demand Reduction Obligation multiplied by the Day-Ahead LMP for the Dispatch Zone or Node at which the resource is registered.

9.2 Real-Time Settlement

A Market Participant with a Demand Response Resource will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the hourly Real-Time LMP for the Dispatch Zone or Node at which the resource is registered.

9.3 Cost Allocation

Charges or payments resulting from Real-Time demand reductions produced by Demand Response Resources or Real-Time Emergency Generation Resources shall be allocated on an hourly basis proportionally to Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

9.4 NCPC Credits and Charges

A Market Participant with a Demand Response Resource is eligible for NCPC credits if the resource is following Dispatch Instructions. A Market Participant with a Demand Response Resource is ineligible for NCPC credits and may be assessed NCPC charges if the resource is not operating within the acceptable dispatch tolerance. A resource is not operating within the acceptable dispatch tolerance if in any five-minute interval for an hour the resource is not operating within 10% above or below the resource's Dispatch Instruction, except that a Market Participant with a resource that is not operating within the acceptable dispatch tolerance will not be assessed NCPC charges if during the entire hour the resource operates within 5% above or below the resource's Dispatch Instruction.

10. Average Avoided Peak Distribution Losses

For purposes of Section III.E2, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder," "hereto," "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Adjusted Audited Demand Reduction is the Audited Demand Reduction of a Demand Response Resource adjusted in accordance with Section III.13.7.1.5.10.1.1.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

Allocated Assessment is a Covered Entity's right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Capacity Price Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.8 of Market Rule 1.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technologies Regulation Pilot Program is the pilot described in Appendix J to Market Rule 1.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annualized FCA Payment is used to determine a resource's availability penalties and is calculated in accordance with Section III.13.7.2.7.1.2(b) of Market Rule 1.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

APR-1 means the first of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-2 means the second of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-3 means the third of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

Asset is a generating unit, interruptible load, a component of a demand response resource or load asset.

Asset Registration Process is the ISO business process for registering a physical load, generator, or tie-line for settlement purposes. The Asset Registration Process is posted on the ISO's website.

Asset Related Demand is a physical load that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of one or more individual end-use metered customers receiving service from the same point or points of electrical supply, with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net risk-adjusted going forward costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Audited Demand Reduction is the seasonal claimed capability of a Demand Response Resource as established pursuant to Section III.13.6.1.5.4.

Audited Full Reduction Time is the Offered Full Reduction Time associated with the Demand Response Resource's most recent audit.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a generating unit change its output while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (iv) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource’s capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource’s Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart CIP Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 utilizing data from Table 6 of Appendix A to this Schedule 16, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Blackstart Station’s costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Blackstart CIP O&M Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a

Blackstart Station's operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision of Blackstart Service.

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual compensation, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, for a Designated Blackstart Resource's operating and maintenance costs associated with the provision of Blackstart Service (except for operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT, which also encompasses "System Restoration and Planning Service" under the predecessor version of Schedule 16.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Station-specific Rate CIP Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capability Year means a year's period beginning on June 1 and ending May 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on July 14, 2014.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22 and Schedule 23 of the OATT.

Capacity Carried Forward Due to Rationing is described in Section III.13.2.7.8.2.1(c)(b)(ii) of Market Rule 1.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Clearing Price Floor is described in Section III.13.2.7.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible, equal to that Market Participant's Capacity Requirement (if any) adjusted to account for any relevant Capacity Load Obligation Bilaterals, as described in Section III.13.7.3.1 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on July 14, 2014.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Requirement is described in Section III.13.7.3.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity-to-Service Ratio is defined in Section III.3.2.2(h) of Market Rule 1.

Capacity Transfer Right (CTR) is a financial right that entitles the holder to the difference in the Net Regional Clearing Prices between Capacity Zones for which the transfer right is defined, in the MW amount of the holder's entitlement.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Value is the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.7.1.5 of Market Rule 1.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Carried Forward Excess Capacity is calculated as described in Section III.13.2.7.8.2.1(c) of Market Rule 1.

Category A Designated Blackstart Resource is a Designated Blackstart Resource that has committed to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 and has not been converted to a Category B Designated Blackstart Resource.

Category B Designated Blackstart Resource is a Designated Blackstart Resource that is not a Category A Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each power year, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset in all Load Zones. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.A of that policy.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Generating Capacity Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(iii) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2017, Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts of a Demand Response Resource scheduled by the ISO as a result of the Day-Ahead Energy Market, multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1 and purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(ii) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(i) of Market Rule 1.

Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Program. The Day-Ahead Load Response Program allows Market Participants with registered Load Response Program Assets to make energy reduction offers into the Day-Ahead Load Response Program concurrent with the Day-Ahead Energy Market.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(iv) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(h) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(g) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.E1.6 and Section III.E2.6.

Demand Reduction Value is the quantity of reduced demand calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

Demand Resource is a resource defined as Demand Response Capacity Resources, On-Peak Demand Resources, Seasonal Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area pursuant to Appendix III.E1 and Appendix III.E2 of Market Rule 1, or during Demand Resource On-Peak Hours, Demand Resource

Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

Demand Resource Commercial Operation Audit is an audit initiated pursuant to Section III.13.6.1.5.4.4.

Demand Resource Forecast Peak Hours are those hours, or portions thereof, in which, absent the dispatch of Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast.

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Operable Capacity Analysis means an analysis performed by the ISO estimating the expected dispatch hours of active Demand Resources given different assumed levels of Demand Resources clearing in the primary Forward Capacity Auction.

Demand Resource Performance Incentives means the additional monthly capacity payment that a Demand Resource may earn for producing a positive Monthly Capacity Variance in a period where other Demand Resources yield a negative monthly capacity variance.

Demand Resource Performance Penalties means the reduction in the monthly capacity payment to a Demand Resource for producing a negative Monthly Capacity Variance.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and the pumping load associated with pumped storage generators) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability ~~the electricity consumption~~ of an individual end-use customer at a Retail Delivery Point or the aggregated ~~electricity consumption~~ demand reduction capability of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2. The demand reduction of a Demand Response Asset is the difference between the Demand Response Asset's actual demand measured at the Retail Delivery Point, which could reflect Net Supply, at the time the Demand Response Resource to which the asset is associated is dispatched by the ISO, and its adjusted Demand Response Baseline.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8A or Section III.8B.

Demand Response Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Demand Response Resource Notification Time is the minimum time, from the receipt of a Dispatch Instruction, that it takes a Demand Response Resource that was not previously reducing demand to start reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the time required from the time a Demand Response Resource that was not previously reducing demand starts reducing demand in response to a Dispatch Instruction and the time the resource achieves its Minimum Reduction.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for generation and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) is the Dispatch Rate expressed in megawatts.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Resources, change External Transactions, or change the status of a Dispatchable Asset Related Demand in accordance with the ~~Resource's or contract's~~ Supply Offer, ~~or~~ Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output, consumption or demand reduction level of each generating Resource, ~~and each~~ Dispatchable Asset Related Demand and ~~each~~ Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.13.1.4.6.1.

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions and must meet the technical requirements specified in the ISO New England Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources, however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation resources directly connected to end-use customer load and located behind the end-use customer's meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a wind resource must not exceed.

DR Auditing Period is the summer DR Auditing Period or winter DR Auditing Period as defined in Section III.13.6.1.5.4.3.1.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at or below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.
Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output level to which a Resource would have been dispatched, based on the Resource's Supply Offer and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a resource that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the resource's Supply Offer. This represents the highest MW output a Market Participant has offered for a resource for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit for all hours in which a resource has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min (a) for Resources with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for Resources without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Resource and with meeting all environmental regulations and licensing limits, and (c) for Resources undergoing Facility and Equipment Testing or auditing, the level to which the Resource requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for non-dispatchable Resources the output level at which a Market Participant anticipates its non-dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the set of Supply Offer values that are used for NCPC calculation purposes as specified in Section III.F.1.a.

EFT is electronic funds transfer.

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.5 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

Elective Transmission Upgrade Applicant is defined in Section II.47.5 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electronic Dispatch Capability is the ability to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of generating units and Dispatchable Asset Related Demands and the ability to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Resources.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum generation amount, in MWs, that a generating unit can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange as determined by the ISO settlement process for the Energy Market.

Energy Offer Cap is $1,000/MWh.

Energy Offer Floor is negative $150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours and Energy Non-Zero Spot Market Settlement Hours.

Enrolling Participant is the Market Participant that registers Customers for the Load Response Program.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORd) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, the Capacity Requirement from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Estimated Net Regional Clearing Price (ENRCP) is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted by certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, and, subject to ISO evaluation, for the Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

Existing Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.1 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; (v) is capable of receiving and acknowledging a Dispatch Instruction electronically; and (vi) has satisfied its Minimum Time Between Reductions.

Fast Start Generator means a generating unit that the ISO may dispatch within the hour through electronic dispatch and that meets the following criteria: (i) minimum run time does not exceed one hour; (ii) minimum down time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Payment is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule

20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Forecast Hourly Demand Reduction means the estimated maximum quantity of energy reduction (MWh), measured at the end-use customer meter that can be produced by a Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource, in each hour of an Operating Day. For a Real-Time Emergency Generation Asset that is metered at the generator and associated with a Real-Time Emergency Generation Resource, the Forecast Hourly Demand Reduction means the estimated maximum generator output (MWh) in each hour of an Operating Day.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual descending clock auction in the Forward Capacity Market, as described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $14,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a generator that has been registered in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant’s senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Adjusted Audited Demand Reduction is calculated in accordance with Section III.13.7.1.5.10.1.2.

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.2.7.1.1.1(a) of Market Rule 1.

Hourly Real-Time Demand Response Resource Deviation means the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.7.3.1.

Hourly Real-Time Emergency Generation Resource Deviation is calculated pursuant to Section III.13.7.1.5.8.3.1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH’s percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH’s percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadequate Supply is defined in Section III.13.2.8.1 of Market Rule 1.

Inadvertent Energy Revenue is defined in Section III.3.2.1(k) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(l) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled generation at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Insufficient Competition is defined in Section III.13.2.8.2 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement" or the "Small Generator Interconnection Agreement" pursuant to Schedules 22 and 23 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 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures" or the "Small Generator Interconnection Procedures" pursuant to Schedules 22 and 23 of the ISO OATT.

Interconnection Request has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Intermittent Power Resource is defined in Section III.13.1.2.2.2 of Market Rule 1.

Intermittent Settlement Only Resource is a Settlement Only Resource that is also an Intermittent Power Resource.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market

Participant’s or Non-Market Participant Transmission Customer’s senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, ~~or~~ Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means generating resources that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, or Real-Time Demand Response Event Hours to other hours and reduce the amount of capacity needed, while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, chilled water storage, and other forms of electricity storage.

Load Response Program means the program implemented and administered by the ISO to promote demand side response as described in Appendix E to Market Rule 1.

Load Response Program Asset means one or more individual end-use metered customers that report load reduction and consumption, or generator output as a single set of values, are assigned an identification number, that participate in the Load Response Program and which encompass assets registered in the Real-Time Price Response Program or Real-Time Demand Response Assets, and are further described in Appendix E of Market Rule 1.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed

Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone or Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location also is a Dispatch Zone.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

Long Lead Time Generating Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart CIP Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Major Transmission Outage is a major transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b)(v) of Market Rule 1.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1, to meet the Installed Capacity Requirement.

Maximum Consumption Limit is the maximum amount, in MW, available from the Dispatchable Asset Related Demand for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data except that a Self-Scheduled Dispatchable Asset Related Demand may modify its Minimum Consumption Limit on an hourly basis, as part of its Demand Bid, in order to indicate the desired level of Self-Scheduled MW.

Maximum Facility Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand of a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset, where the demand evaluated is established by adding actual metered demand and the output of all generators located behind the asset's end-use customer meter in the same time intervals.

Maximum Generation is the maximum generation output of a Real-Time Demand Response Asset comprised of Distributed Generation or the maximum generation output of a Demand Response Asset comprised of Distributed Generation.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response

Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset's peak load less its uninterruptible load. For assets that deliver reductions through the use of generation, the Maximum Interruptible Capacity is the difference between the generator's maximum possible output and its expected output when not providing demand reduction. For assets that deliver demand reduction and Net Supply, the Maximum Interruptible Capacity is the asset's peak load plus Maximum Net Supply as measured at the Retail Delivery Point.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, of a Demand Response Asset, Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

Maximum Net Supply is an estimate of the maximum hourly Net Supply for a Demand Response Asset as measured from the Demand Response Asset's Retail Delivery Point.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time a Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the Demand Reduction Value of the Demand Resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the Demand Reduction Value for an Existing Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1, which includes Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by a Demand Resource supplier as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by Demand Resource suppliers during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Minimum Consumption Limit is the minimum amount, in MW, available from a Dispatchable Asset Related Demand that is not available for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data.

Minimum Down Time is the number of hours that must elapse after a Generator Asset has been released for shutdown at or below its Economic Minimum Limit before the Generator Asset can be brought online and be released for dispatch at its Economic Minimum Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources to operate at or below Economic Minimum Limit, in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit.

Minimum 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 Time Between Reductions is the minimum number of hours that a Market Participant requires between the time the Demand Response Resource receives a Dispatch Instruction from the ISO to not reduce demand and the time the Demand Response Resource receives a Dispatch Instruction from the ISO to reduce demand.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Variance means a Demand Resource's actual monthly Capacity Value established pursuant to Section III.13.7.1.5.1 of Market Rule 1, minus the Demand Resource's final Capacity Supply Obligation for the month.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NERC is the North American Electric Reliability Corporation or its successor organization.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

Net Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

Net Supply is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.

~~**Net Supply Generator Asset** is the Generator Asset registered in the energy market at the same Retail Delivery Point as a Demand Response Asset with Distributed Generation capable of delivering Net Supply.~~

Net Supply Limit is the estimated portion of the offered Maximum Reduction of a Demand Response Resource that would be provided through Net Supply. The Net Supply Limit is calculated by multiplying the offered Maximum Reduction of the Demand Response Resource by the ratio of total Net Supply to total demand reduction performance from the prior like Seasonal DR Audit of the Demand Response Assets that are mapped to the Demand Response Resource for the month.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource, as described in Section III.13.2.3.2 of Market Rule 1.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Required is the amount of additional capacity required to meet the Installed Capacity Requirement or a Capacity Zone's Local Sourcing Requirement, as described in Section III.13.2.8.1.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.2 of Market Rule 1.

New Demand Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III 13.1.4.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Resource.

New Demand Resource Show of Interest Form is described in Section III.13.1.4.2 of Market Rule 1.

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but does not have a winter audit value and a summer audit value.

New Demand Response Asset Audit is an audit of a New Demand Response Asset performed pursuant to Section III.13.6.1.5.4.8.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Nodal Amount is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a generating unit that must be paid to Market Participants with an Ownership Share in the unit for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the generating unit is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.3.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an increment of an Existing Capacity Resource that is treated as a New Capacity Resource in the Forward Capacity Auction and that has not been declared commercial and has not had its capacity rating verified by the ISO.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Intermittent Settlement Only Resource is a Settlement Only Resource that is not an Intermittent Power Resource.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-Price Retirement Request is a binding request to retire the entire capacity of a Generating Capacity Resource as described in Section III.13.1.2.3.1.5.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2017. Demand Response Resources for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is, for a generating Resource, a Supply Offer value between 0 and the CLAIM10 of ~~a~~ the Resource that represents the amount of TMNSR available from the Resource from an off-line state, and, for a Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched, is a Demand Bid or Demand Reduction Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR or TMSR available from the Resource.

Offered CLAIM30 is a Supply Offer, Demand Bid or Demand Reduction Offer value between 0 and the CLAIM30 of a Resource that represents the amount of ~~offline~~ TMOR available from ~~the Resource~~ an off-line generating Resource, or Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched.

Offered Full Reduction Time is the value calculated pursuant to Section III.13.6.1.5.4.6.

On-Peak Demand Resource is a type of Demand Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement.

With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a generating unit asset or Load Asset, where such unit or load is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The "Phase II Transfer Capability" is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource or New Demand Resource participate in the Forward Capacity Market, as described in Section III.13.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b)(iii) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(c)(iii) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E1.8 for Capacity Commitment Periods commencing prior to June 1, 2017, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2017.

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Real-Time Demand Response Resources of such hours.

Real-Time Demand Response Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Demand Response Resource.

Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

Real-Time Emergency Generation Resource is Distributed Generation whose federal, state and/or local air quality permits, rules or regulations limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(ii) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(c)(ii) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b)(i) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(c)(i) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b)(iv) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(c)(iv) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Price Response Program is the program described in Appendix E to Market Rule 1.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as

Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

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 Capability (REGCAP) means the amount of Regulation capability available on a Market Participant’s Resource as calculated by the ISO based upon that Resource’s Automatic Response Rate and the available regulating range as specified in ISO New England Manual 11 – Market Operations.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.

Regulation Rank Price is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

Regulation Requirement is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

Regulation Service Credit is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

Regulation Service Megawatts are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, for Capacity Commitment Periods commencing on or after June 1, 2017, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2017, a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New

England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

Seasonal Peak Demand Resource is a type of Demand Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Self-Schedule is the action of a Market Participant in committing or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing or scheduling a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been scheduled or dispatched by the ISO to provide the Energy. For a Dispatchable Asset Related Demand, Self-Schedule is the action of a Market Participant in committing or scheduling a Dispatchable Asset Related Demand to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the Dispatchable Asset Related Demand would have been scheduled or dispatched by the ISO to consume Energy. Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to: (i) a Generator Asset's Economic Minimum Limit; (ii) a Dispatchable Asset Related Demand's Minimum Consumption Limit; or (iii) for Regulation purposes with respect to a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource’s capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource’s capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, or Schedule 23 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of (1) a generating ~~unit~~ Resource that can be converted fully into energy within ten minutes from the request of the ISO~~, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of~~ (2) a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO.

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Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of (1) a generating ~~unit~~ Resource that is electrically synchronized to the New England Transmission System that can be converted fully into energy within ten minutes from the request of the ISO; (2) ~~or~~ a Dispatchable Asset Related Demand pump that is electrically synchronized to the New England Transmission System that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO~~, and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System~~; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO for which none of the associated Demand Response Assets have a generator whose output can be controlled located behind the Retail Delivery Point other than emergency generators that cannot operate electrically synchronized to the New England Transmission System.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) means the reserve capability of (1) a generating ~~unit~~ Resource that can be converted fully into energy within thirty minutes from the request of the ISO~~, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of~~ (2) a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within thirty minutes from the request of the ISO.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Time-on-Regulation Credit is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

Time-on-Regulation Megawatts is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart O&M Payment is the annual compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Supplemental Availability Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 Requirements for Certain Transactions.

III.1.4.1 ISO Settlement of Certain Transactions.

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 Transactions Subject to Requirements of Section III.1.4.

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Supplemental Availability Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as "Section III.1.4 Transactions," and individually as a "Section III.1.4 Transaction." Transactions that conform to the standards are referred to collectively as "Section III.1.4 Conforming Transactions," and individually as a "Section III.1.4 Conforming Transaction."

III.1.4.3 Requirements for Section III.1.4 Conforming Transactions.

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a "Related Transaction"), where the Related Transaction:

(i) is not cleared or settled by the ISO as Counterparty;

(ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

(iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and

(iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

(b) In addition, to qualify as a Section III.1.4 Conforming Transaction:

(i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;

(ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and

(iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

(i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and

(ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

(a) Three types of Claimed Capability Audits may be performed:

- (i) An Establish Claimed Capability Audit establishes the Generator Asset’s ability to respond to ISO dispatch instructions and to maintain performance at a specified output level for a specified duration.
- (ii) A Seasonal Claimed Capability Audit determines a Generator Asset’s capability to perform under specified summer and winter conditions for a specified duration.

(iii) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value.

(b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.

(d) The Claimed Capability Audit value for steam turbine assets with 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) The time and date of an Establish Claimed Capability Audit shall be unannounced.

(b) For a newly commercial Generator Asset:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within seven Business Days of the commercial operation date for all Generator Assets except:

1. Non-intermittent daily cycle hydro;
2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
3. Intermittent Generator Assets

(ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.

(c) For Generator Assets with an Establish Claimed Capability Audit value:

(i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.

(ii) An Establish Claimed Capability Audit shall be performed within seven Business Days of the date of the request.

(iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iv) The Establish Claimed Capability Audit values become effective seven Business Days following notification of the audit results to the Market Participant by the ISO.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(d) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.

(e) Establish Claimed Capability Audits shall be performed on Business Days between 0800 and 2200.

(f) To conduct an Establish Claimed Capability Audit, the ISO shall:

(i) Notify the Designated Entity immediately prior to issuing the Dispatch Instruction that an audit will be conducted.

(ii) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the asset's net output to increase from the current operating level to its Real-Time High Operating Limit.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.

(g) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
Unit Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible	2

Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2

III.1.5.1.3. Seasonal Claimed Capability Audits.

(a) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:

(i) Non-intermittent daily hydro; and

(ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

(b) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's Seasonal Claimed Capability Audit obligation.

(c) Except as provided in Section III.1.5.1.3(m) below, a summer Seasonal Claimed Capability Audit must be conducted:

(i) At least once every Capability Demonstration Year;

(ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.

(d) A winter Seasonal Claimed Capability Audit must be conducted:

(i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:

(1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.

(2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.

(ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.

(e) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the seventh Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.

(f) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(g) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(c) and (d), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(h) The Seasonal Claimed Capability Audit value shall become effective seven Business Days following notification of the audit results to the Market Participant by the ISO.

(i) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Unit Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2
Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible	2
Hydro-Conventional Weekly	2

(j) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal

Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;

(ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

(iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.

(k) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;

(ii) Retain the current Seasonal Claimed Capability Audit value for the season; and

(iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.

(l) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

(m) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:

(i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(e).

(ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.

(iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.

(iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(c)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.

(v) This Section III.1.5.1.3(m) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

(a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.

(b) An ISO-Initiated Claimed Capability Audit value shall replace the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:

(i) The Establish Claimed Capability Audit values may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.

(c) If a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.

(d) Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective seven Business Days following notification of the audit results to the Market Participant by the ISO.

(e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:

(i) Notify the Designated Entity, immediately prior to issuing the Dispatch Instruction, that an audit will be conducted.

(ii) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.

(f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit	
Unit Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2

III.1.5.2 ISO-Initiated Parameter Auditing.

(a) The ISO may perform an audit of any Supply Offer, Demand Reduction offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide real-time energy or reserves.

(b) ~~Audits~~ 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 Dispatch Instruction.

(ii) **Manual Response Rate**. The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.

(iii) **Start-Up Time**. The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.

(iv) **Notification Time**. The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.

(v) **CLAIM10**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5 ~~of Market Rule 1~~.

(vi) **CLAIM30**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5 ~~of Market Rule 1~~.

(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 ~~ISO-issued~~ electronic Dispatch Instructions.

(viii) **Dual Fuel Capability.** A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(e).

(c) Demand Response Resource audits shall be performed using the following methods:

(i) **Maximum Reduction**. The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Resource Ramp Rate**. The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.

(iii) **Demand Response Resource Start-Up Time**. The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

(iv) **Demand Response Resource Notification Time**. The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

(v) **CLAIM10**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5.

~~(c)~~(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 ~~ISO~~ Dispatch Instructions; or

(ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to ~~ISO~~ Dispatch Instructions.

~~(d)~~(e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset~~'s net output~~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.

~~(e)~~(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.

(iii) Market Participants will be compensated for audits of dual fuel capability conducted under this Section III.1.5.2 pursuant to Appendix F. If a Market Participant has a Generator Asset that cleared in the Day-Ahead Energy Market and the Market Participant is audited for all or part of the Generator Asset's Day-Ahead schedule on a fuel other than the fuel that formed the basis of the Generator Asset's Supply Offer in the Day-Ahead Energy Market, and

Appendix F would otherwise not compensate the Generator Asset on the higher-priced fuel, then the Market Participant will receive additional compensation equal to the difference between 1) the audit costs based on the cost-based Reference Levels calculated using the fuel on which the audit was performed and 2) amounts calculated for that same operation as reflected in the greater of the Day-Ahead Supply Offer and the cost-based Reference Levels calculated using the fuel on which the Day-Ahead Supply Offer was based. Compensation pursuant to this Section III.1.5.2(e)(iii) shall be charged in accordance with Section III.F.3.2.19 of Appendix F.

~~(f)~~(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.

~~(g)~~(h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:

(i) The ~~Lead~~ 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.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 ISO New England Manuals and ISO New England Administrative Procedures.

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 [Reserved.]

III.1.7.6 Scheduling and Dispatching.

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch.

(b) In the event that one or more Resources cannot be scheduled in the Day-Ahead Energy Market on the basis of a least-cost, security-constrained dispatch as a result of one or more Self-Schedule offers contributing to a transmission limit violation, the following scheduling protocols will apply:

(i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.

(ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.

(iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy, including demand reductions, bought and sold in the New England Markets will reflect the hourly Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices in an hour caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices in an hour, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect the integrated hourly Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.10 Other Transactions.

(a) Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the obligations of Market Participants to make resources with a Capacity Supply Obligation available for dispatch by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

(b) [Reserved.]

(c) [Reserved.]

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

(a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.

(b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.

(c) The Seasonal Claimed Capability of a Generator Asset is:

(i) Based upon review of historical data for non-intermittent daily cycle hydro.

(ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.

(iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:

a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.

b. For a Generator Asset that is off-line and not available for commitment shall be zero.

c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.

(iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

III.1.7.12 [Reserved.]

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall schedule ~~to~~ the Operating Reserve and load-following requirements of the New England Control Area and the New England Markets in scheduling Resources pursuant to this Market Rule 1. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Regulation.

(a) Regulation shall be supplied from generators located within the metered electrical boundaries of the New England Control Area. Market Participants offering Regulation shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall obtain and maintain an amount of Regulation equal to the New England Control Area Regulation objective as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) The Regulation range of a unit shall be at least twice the amount of Regulation assigned and no less than the minimum specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(d) A unit that is providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided. The amount of Regulation provided by a unit shall serve to redefine the Economic Minimum Limit and Economic Maximum Limit of that unit, in that the amount of Regulation shall be added to the unit's Economic Minimum Limit or automatic low limit while regulating, whichever is greater, and subtracted from its Economic Maximum Limit or automatic high limit, which ever is less. Qualified Regulation must satisfy the verification tests described in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19 Ramping.

A generating unit or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the unit's megawatt output or demand reduction level shall be able to change output or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that unit and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19A Real-Time Reserve.

(a) Real-Time TMSR, TMNSR, TMOR and Real-Time Replacement Reserve, if applicable, shall be supplied from Resources located within the metered boundaries of the New England Control Area subject to the condition set forth in Section III.1.7.19A(c) below. The ISO shall designate Operating Reserve in Real-Time only to Market Participant Resources that comply with the applicable standards and requirements for provision and dispatch of Operating Reserve capability as specified in Section III.10 and the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and locational Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) External Resources will be permitted to participate in the Real-Time reserve market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO units that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output or demand reduction levels of generating units or Demand Response Resources, or change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating and demand reduction equipment is operated with control equipment functioning as specified in the ISO New England Manuals ~~&~~ and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market, along with Dispatch Rate levels above which it does not desire to purchase.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output or demand reduction capability for the pertinent Operating Day.

III.1.8 [Reserved.]

III.1.9 Pre-scheduling.

III.1.9.1 [Reserved.]

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each generating unit as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline specified in the ISO New England Manuals and ISO New England Administrative Procedures and shall remain in effect without change throughout each such period for which a specification was submitted. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area.

Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of generating Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers for such units.

III.1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 10:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resource increments, including hydropower units, Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be equal to or greater than zero and shall not exceed the energy Supply Offer limitation specified in this Section.

(b) [Reserved.]

(c) All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to $0.0/MWh; and

(iv) If the sum of all submitted fixed External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all fixed External Transaction sales at the applicable External Node shall be set equal to $1,000/MWh.

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(d) Market Participants selling into the New England Markets, from either internal Resources or External Resources, shall submit Supply Offers or External Transactions for the supply of energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Regulation, Operating Reserve or other services as applicable, for the following Operating Day. Supply Offers shall be submitted to the ISO in the form specified by the ISO and shall contain the information specified in the ISO's Offer Data specification, as applicable. External Transactions shall be submitted to the ISO according to Section III.1.10.7 of this Market Rule 1. The ISO shall not consider Start-Up Fees, No-Load Fee, notification times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

Energy offered from generating Resources without a Capacity Supply Obligation shall not be supplied from Resources that are included in or otherwise committed to supply the operating reserve requirements of another Control Area. All Supply Offers and Demand Bids:

(i) Shall specify the Resource and energy for each hour in the offer period;

(ii) Shall specify the amounts and prices for the entire Operating Day for each Resource offered by the Market Participant to the ISO;

(iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify Start-Up Fees and No-Load Fee equal to the specification of such fees for such unit on file with the ISO (Market Participant changes to the Start-Up Fee and No-Load Fee can only occur during the open periodic bidding enrollment periods (daily));

(iv) Shall set forth any special conditions upon which the Market Participant proposes to supply a Resource increment;

(v) Shall specify a minimum run time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;

(vi) Shall constitute an offer to submit the generating Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Economic Minimum Limit may be revised to reflect the Self-Scheduled output level of the Resource and for a Limited Energy

Resource, the Economic Maximum Limit may be revised to reflect maximum energy available for the Operating Day, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;

(vii) Shall constitute an offer to submit the Dispatchable Asset Related Demand Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes to the Maximum Consumption Limit and Minimum Consumption Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Minimum Consumption Limit may be revised to reflect the Self-Scheduled consumption level of the Resource;

(viii) Shall be final as to the price or prices at which the Market Participant proposes to supply or consume energy or other services to the New England Markets, such price or prices for Resources or portions of Resources scheduled in the Day-Ahead Energy Market being guaranteed by the Market Participant for the period extending through the end of the following Operating Day; and

(ix) Shall not specify an energy offer or bid price below $0/MWh or above $1,000/MWh.

(e) A Market Participant that wishes to make a Resource available to sell Regulation service shall submit a Supply Offer for Regulation that shall specify the Automatic Response Rate in megawatts per minute, the price in dollars per MWh of the Regulation capability being offered, such Regulation capability as calculated by the ISO by multiplying the submitted Automatic Response Rate by five minutes, and such other information specified by the ISO as may be necessary to evaluate the Supply Offer and the generating Resource's Regulation Opportunity Costs. The price of the Supply Offer shall not exceed $100/MWh. Qualified Regulation capability must satisfy the verification tests specified in the ISO New England Manuals and ISO New England Administrative Procedures. Regulation capability amounts will be adjusted as necessary in the case where a generating unit's compliance rating is less than 90%. The audited Regulation capability will be deemed equal to the most recently calculated compliance rating times the 5-minute Regulation capability quantities utilized in that compliance rating calculation, rounded to the nearest whole megawatt. The Resource's Automatic Response Rate will then be adjusted based upon the audited Regulation capability.

(f) [Reserved.]

(g) Each Supply Offer or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Resource and an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days.

(h) The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits ~~and~~, 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, ~~and~~ Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids. Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers or Demand Reduction Offers to sell energy in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as generators or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide energy in the Real-Time dispatch unless the schedules for such ~~units~~ Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(b) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

(c) Market Participants offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) The Market Participant seller whose Resource is selected as a Pool-Scheduled Resource shall receive payments or credits for energy or related services, or for Start-Up Fees~~ and~~ , No-Load Fees or Interruption Costs, from the ISO on behalf of the Market Participant buyers in accordance with Section III.3 of this Market Rule 1.

(e) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

Self-Scheduled Resources shall be governed by the following principles and procedures.

(a) [Reserved.]

(b) The offered prices of Resources or portions of Resources that are Self-Scheduled, or otherwise not following the dispatch orders of the ISO, shall not be considered by the ISO in determining Locational Marginal Prices.

(c) A Market Participant with a Resource that does not have a Capacity Supply Obligation shall comply with the requirements in Section III.13.6.2 when Self-Scheduling any portion of that Resource.

(d) A Market Participant Self-Scheduling a Resource in the Day-Ahead Energy Market that does not deliver the energy in the Real-Time Energy Market, shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.4 [Reserved.]

III.1.10.5 External Resources.

(a) Market Participants with External Resources that have dynamic scheduling and dispatch capability may submit Supply Offers to the New England Markets in accordance with the Day-Ahead and Real-Time scheduling processes specified above. Market Participants must submit Supply Offers for External Resources on a Resource specific basis. An External Resource with dynamic scheduling and dispatch capability selected as a Pool-Scheduled Resource shall be made available for scheduling and dispatch at the direction of the ISO and shall be compensated on the same basis as other Pool-Scheduled Resources.

(b) Supply Offers for External Resources with dynamic scheduling and dispatch capability shall specify the Resource being offered, along with the information specified in the Offer Data as applicable.

(c) For Resources external to the New England Control Area that are not capable of dynamic scheduling and dispatch, Market Participants shall submit External Transactions as detailed in Section III.1.10.7 of this Market Rule 1.

(d) A Market Participant whose External Resource is capable of dynamic scheduling and dispatch capability or whose External Transaction does not deliver the energy scheduled in the Day-Ahead Energy Market shall replace such energy not delivered as scheduled in the Day-Ahead Energy Market with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.6 Dispatchable Asset Related Demand Resources.

External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demand Resources. Except as noted below with respect to a pumped storage generator that does not have a Capacity Supply Obligation, a Dispatchable Asset Related Demand Resource in the New England Control Area must:

(a) each day, either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy, unless and to the extent that the Dispatchable Asset Related Demand Resource is unable to do so due to an outage as defined in the ISO New England Manuals;

(b) submit Demand Bid data that specifies a Maximum Consumption Limit and Minimum Consumption Limit;

(c) submit Demand Bid data that specifies a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit;

(d) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand Resource's ability to interrupt and the expected return date from the outage;

(e) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;

(f) abide by the ISO maintenance coordination procedures;

(g) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand Resource; and

(h) comply with the ISO New England Manuals.

To schedule the dispatchable pumping demand of a pumped storage generator that does not have a Capacity Supply Obligation, a Market Participant must comply with the requirements in (b) through (h) for the applicable Operating Day and must either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy for the applicable Operating Day.

III.1.10.7 External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the applicable procedures governing the Emergency, as set forth in ISO New England Manual 11, require a change in schedule.

(d) A Market Participant submitting a priced External Transaction supporting Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must comply with the requirements in Section III.13.6.1.2.1 with respect to linking the transaction to the associated transmission reservation and NERC E-Tag. All other External Transactions submitted to the Real-Time Energy Market must contain the associated NERC E-Tag and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) All Real-Time External Transactions shall be scheduled and curtailed in accordance with the ISO New England Manuals and all applicable tariffs.

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.8 ISO Responsibilities.

(a) The ISO shall use its best efforts to determine (i) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market. In making these determinations, the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England

Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Pool-Scheduled Resources and to direct that schedules be changed in an Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to generation Supply Offers and revisions to Demand Bids for any Dispatchable Asset Related Demand Resource. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) A Market Participant may adjust the schedule of a Resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the ISO is notified not later than 20 minutes prior to the hour, as follows:

(i) A Market Participant may Self-Schedule any of its Resources consistent with the ISO New England Manuals and ISO New England Administrative Procedures;

(ii) [Reserved]; or

(iii) [Reserved]; or

(iv) A Market Participant may remove from service a Resource increment previously designated as Self-Scheduled consistent with the ISO New England Manuals and ISO New England Administrative Procedures.

(c) During the Re-Offer Period, Market Participants may submit revisions to priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may at any time, consistent with the provisions in Manual 11, request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect.

(d) **[Reserved.]**

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output or demand reduction of any Pool-Scheduled Resource increment within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output or demand reduction of Pool-Scheduled Resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (c) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Pool-dispatched Resources.

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Pool-Scheduled Resource increments and the designation of Real-Time Operating Reserve to Pool-Scheduled Resource increments, including the dispatchable increments from resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall ensure that the entity controlling a Pool-Scheduled Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to dispatched output or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Wind resources are treated as not economically dispatchable until the ISO is technically capable of determining and telemetering a Do Not Exceed Dispatch Point to the resource.

(f) The ISO may request that dual-fueled generating Resources that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fueled units that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fueled units that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 Regulation.

(a) A Market Participant may satisfy its Regulation obligation from its own Resources capable of performing Regulation service or by purchases from the ISO through the New England Markets at the rates set forth in Section III.3.2.2.

(b) The ISO shall obtain Regulation service from the least-cost alternatives available from either Pool-Scheduled Resources or Self-Scheduled Resources as needed to meet New England Control Area requirements not otherwise satisfied by the Market Participants. The ISO assigns Regulation to eligible generating units using the ISO Regulation assessment software. The Regulation assessment software calculates, at five minutes after the hour and on demand as needed, the optimal set of generating units required to meet the Regulation Requirement. The software first calculates a Regulation Rank Price, based on estimates of Time-on-Regulation Credits, Regulation Service Credits, estimated Regulation Opportunity Costs, Regulation Capability and other factors, as specified below, that consider the impact of Regulation assignment on the Real-Time Energy Market. An interim clearing price is then calculated and the Regulation Rank Prices are updated using this interim clearing price to recognize that actual payments for Regulation are based upon the Regulation Clearing Price and not the Regulation offer price. The software continues to iterate in this manner until convergence is reached, resulting in an optimal selection of generating units for Regulation assignment. The ISO utilizes the output from this software when evaluating the set of generating units for Regulation assignment. In the event that one or more generating units to be selected have equal Regulation Rank Prices, the ISO shall select the generating unit for Regulation assignment with the largest Regulation Capability. Details of the process and calculations are described below.

(1) At the start of each operating hour, the ISO calculates an initial Regulation Rank Price for each eligible unit offering to provide Regulation using the ISO's Regulation assignment software. The initial Regulation Rank Price for each unit is equal to the sum of the following calculations divided by that unit's Regulation Capability:

(a) Time-on-Regulation Credit estimate calculated as the product of the Regulation Capability times the Regulation offer price;

(b) Regulation Service Credit estimate is set equal to the Time-on-Regulation Credit estimate to meet the 50/50 revenue mix objective as determined by the ISO in accordance with procedures specified in the ISO New England Manuals and ISO New England Administrative Procedures;

(c) Regulation Opportunity Cost estimate calculated as the product of the opportunity cost MW times the opportunity cost price differential where:

(i) Opportunity cost MW is calculated as the absolute value of the difference between the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by Economic Max and Economic Min, and EstRegGen.

(ii) EstRegGen is the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by RSETHI and RSETLO. RSETHI is equal to the Regulation High Limit – Regulation Capability. RSETLO is equal to the Regulation Low Limit + Regulation Capability.

(iii) To more accurately estimate the actual Regulation Opportunity Cost, EstRegGen is further constrained as follows to account for units with large regulating ranges and slow response rates: if actual generation is less than EstRegGen and EstRegGen is greater than RSETLO, then EstRegGen is constrained up by the greater of (actual output + (SlowWideTime * Automatic Response Rate)) and RSETLO; if actual generation is greater than EstRegGen and EstRegGen is less than RSETHI, then EstRegGen is constrained down by the lesser of (actual output – (SlowWideTime * Automatic Response Rate)) and RSETHI. The SlowWideTime is determined by the ISO based upon empirical studies. The initial SlowWideTime value, and subsequent updates, shall be posted on the ISO's website.

(iv) Opportunity cost price differential is calculated as the absolute value of the difference between the average offer price of the opportunity MW and the Real-Time nodal LMP of the unit.

(d) Lookahead penalty estimate. The lookahead calculation assigns a cost penalty to units in the selection process if there is a change in energy offer prices near EstRegGen. It is calculated as 0.17 multiplied by the greater of:

(i) the unit's energy offer price at a higher output level (LookupRegGen as defined below) minus its energy offer price at EstRegGen, multiplied by (LookupRegGen – EstRegGen);
and

(ii) the unit's energy offer price at EstRegGen minus its energy offer price at a lower output level (LookdownRegGen as defined below), multiplied by (EstRegGen -LookdownRegGen), where, LookupRegGen = (EstRegGen + (LookAheadMinutesUp * Automatic Response Rate)) as bounded by Regulation High Limit; and LookdownRegGen = (EstRegGen – (LookAheadMinutesDown * Automatic Response Rate) as bounded by Regulation Low Limit), And where the initial values of LookAheadMinutesUp and LookAheadMinutesDown, and subsequent updates, will be posted on the ISO's website.

(e) A tiebreaker adder is calculated for both pool-scheduled and Self-Scheduled Regulation units. The tiebreaker adder is equal to a tiebreaker multiplier (.000001) times the difference between a tiebreaker megawatt reference value (500 MW) and the Regulation Capability of the unit.

For Self-Scheduled Regulation, all values calculated under this Section III.1.11.5(b)(1) are set equal to zero except for the tiebreaker adder.

(2) The ISO's Regulation assignment software creates an initial merit order stack of eligible Regulation Capability by sorting the generating units by the initial Regulation Rank Prices calculated under Section III.1.11.5 (b)(1) in ascending order. Generating units are then selected in rank order until the Regulation Requirement is met. An initial clearing price is then calculated based upon the highest Regulation offer price associated with the initial set of generating units selected to meet the Regulation Requirement. Updated Regulation Rank Prices are then recalculated for generating units with Regulation offer prices that are less than the initial clearing price by substituting the initial clearing price for the generating unit's Regulation offer price, recalculating the Time-On-Regulation Credit and the Regulation Service Credit estimates; adding the originally calculated values under Sections III.1.11.5(b)(1)(c), (d) and (e) to these recalculated values and dividing this total by the unit's Regulation Capability. These updated Regulation Rank Prices are utilized along with the initial Regulation offer prices adjusted to include opportunity costs that are greater than or equal to the initial clearing price to create an updated generating unit list sorted by ascending Regulation Rank Prices. An updated clearing price is then calculated and the software continues to iterate in this manner until convergence is reached producing an optimal generating unit rank order list for use in assigning Regulation.

(3) Shortly after the start of an hour and during the hour as needed, the ISO updates the generating unit rank order list using the ISO's Regulation assignment software based on any

changes to Regulation Capability eligibility and other current information, including any changes to Self-Schedule Regulation. The ISO uses this updated Regulation rank order list to assign Regulation for the upcoming hour and to make changes to Regulation assignments within the hour.

(c) The ISO shall dispatch Resources for Regulation by sending Regulation signals and instructions to Resources from which Market Participants, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, have offered Regulation service. Market Participants shall comply with Regulation dispatch signals and instructions transmitted by the ISO and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources supplying load in the New England Control Area as close to desired output levels as practical, consistent with Good Utility Practice.

III.1.11.6 [Reserved]

III.1.12 Dynamic Scheduling.

Dynamic scheduling can be requested and may be implemented in accordance with the following procedures:

(a) An entity that owns or controls a generating Resource in the New England Control Area may electrically remove all or part of the generating Resource's output from the New England Control Area through dynamic scheduling of the output to load outside the New England Control Area. Such output shall not be available for economic dispatch by the ISO.

(b) An entity that owns or controls a generating Resource outside of the New England Control Area may electrically include all or part of the generating Resource's output into the New England Control Area through dynamic scheduling of the output to load inside the New England Control Area. Such output shall be available for economic dispatch by the ISO.

(c) An entity requesting dynamic scheduling shall be responsible for arranging for the provision of signal processing and communication from the generating unit and other participating Control Area and complying with any other procedures established by the ISO regarding dynamic scheduling as set forth in the ISO New England Manuals. Allocation of costs associated with dynamic scheduling shall be determined and filed with the Commission following the first request.

(d) An entity requesting dynamic scheduling shall be responsible for reserving amounts of appropriate transmission service necessary to deliver the range of the dynamic transfer and any ancillary services.

III.2 LMPs and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of generation supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area, transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.4, every offer of energy by a Market Participant from a generating Resource, Demand Response Resource, an External Transaction purchase Resource and a Dispatchable Asset Related Demand Resource that is following economic dispatch instructions of the ISO will be utilized in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and locational Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the most recent power flow solution produced by the State Estimator, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Determination of Energy Offers Used in Calculating Real-Time Prices and Real-Time Reserve Clearing Prices.

(a) During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market.

(b) To determine the energy offers submitted to the New England Markets that shall be used during the Operating Day to calculate the Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall determine which generating Resources, Demand Response Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources are following its economic dispatch instructions. A generating Resource, Demand Response Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-Time Prices if:

(i) the applicable Supply Offer or Demand Reduction Offer price submitted by a Market Participant for energy from the generating Resource, Demand Response Resource or External Transaction purchase is less than or equal to the Dispatch Rate associated with that ~~generating~~ Resource or External Transaction purchase; ~~and~~

(ii) the applicable Demand Bid price submitted by a Market Participant for energy from the Dispatchable Asset Related Demand Resource is greater than or equal to the Dispatch Rate associated with that Dispatchable Asset Related Demand Resource; ~~and~~

(iii) the generating Resource, other than a Fast Start Generator, is operating at or above its Economic Minimum Limit; ~~or~~

(iv) the Fast Start Generator is operating at or above its Economic Minimum Limit and the applicable Supply Offer price submitted by a Market Participant for energy from the Fast Start Generator is less than or equal to the Dispatch Rate associated with that Fast Start Generator; ~~or~~

(v) The Demand Response Resource, other than a Fast Start Demand Response Resource, is operating at or above its Minimum Reduction;

(vi) The Fast Start Demand Response Resource is operating at or above its Minimum Reduction and the applicable Demand Reduction Offer price submitted by a Market Participant for energy from the Resource is less than or equal to the Dispatch Rate associated with the Resource; and

(vii) the generating Resource, Demand Response Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource is specifically requested to operate or reduce consumption by the ISO's dispatcher and the associated energy offers or bids submitted are otherwise eligible to be included in the calculation of Real-Time Locational Marginal Prices.

(c) In determining whether a generating Resource or External Transaction purchase satisfies the condition described in Section III.2.4(b), the ISO will determine the Supply Offer price associated with an energy offer by comparing the actual megawatt output of the generating unit or External Transaction purchase with the Market Participant's Supply Offer price curve for that generating unit or External Transaction purchase. Because of practical generator response limitations, a generating unit whose megawatt output is not more than ten percent above or below the megawatt level specified in the Supply Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

(d) In determining whether a Dispatchable Asset Related Demand Resource satisfies the condition described in Section III.2.4(b), the ISO will determine the Demand Bid price associated with a Demand Bid by comparing the actual megawatt consumption of the Dispatchable Asset Related Demand Resource with the Market Participant's Demand Bid price curve for that Dispatchable Asset Related Demand Resource. Because of practical Dispatchable Asset Related Demand Resource response limitations, a Dispatchable Asset Related Demand Resource whose megawatt consumption is greater than or equal to ninety percent, and less than or equal to 110% of the megawatt level specified in the Demand Bid price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy demand bid price used in the calculation of Real-Time Prices shall not be lower than the applicable Dispatch Rate.

(e) In determining whether a Demand Response Resource satisfies the condition described in Section III.2.4(b), the ISO will compare the actual megawatt demand reduction of the Demand Response Resource with the Market Participant's Demand Reduction Offer price curve for that Resource. Because of practical response limitations, a Demand Response Resource whose megawatt demand reduction is not more than ten percent above or below the megawatt level specified in the Demand Reduction Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

III.2.5 Calculation of Real-Time Nodal Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, Demand Response Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.8; and (5) the effect on transmission losses caused by the increment of load, ~~and~~ generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of

Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed every five minutes, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5. shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes if the Minimum Generation Emergency was declared on a New England Control Area wide basis or shall be set equal to the Energy Offer Floor for all Nodes and External Nodes within a sub-region if the Minimum Generation Emergency was declared within the sub-region.

III.2.6 Calculation of Day-Ahead Nodal Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions resulting from the load specifications submitted by Market Participants, Supply Offers, Demand Reduction Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying a linear optimization method to minimize energy, congestion and transmission loss costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer or bid as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Node.

The process for clearing External Nodes differs from the process for clearing other Nodes in that, in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available generation at its Economic Maximum Limit and demand reduction at the Demand Response Resource's Maximum Reduction, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction sales are considered to be dispatchable at the Energy Offer Cap;

(ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer or Increment Offer price cleared). Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line generation, dispatched Demand Response Resources, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line generation, dispatched Demand Response Resources, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

(c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide generation MW (including fixed External Transaction purchases) with all possible generation off and with all remaining generation at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic generation in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction purchases are considered to be dispatchable at the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed generation down proportionately by ratio of Economic Minimum Limits but not below Emergency Minimum Limits. If power balance is achieved prior to reaching Emergency Minimum Limits, set LMP values equal to the lowest offer price of all on-line generation; and

(iii) If power balance not achieved in step (ii), set LMP values to Energy Offer Floor and reduce all committed generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.

(a) The ISO shall calculate Zonal Prices for each Load Zone and Dispatch Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets for each hour using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone and Dispatch Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and Dispatch Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

(b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.

(c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.

(d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.

(e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.

(f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.

(g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones and add or subtract Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

(h) In the event the ISO makes changes to a Reliability Region or Load Zone or adds or subtracts Reliability Regions and Load Zones, for settlement purposes and to the extent practicable, Load Assets that are physically located in one Reliability Region and electrically located within another Reliability Region shall be located within the Reliability Region to which they are electrically located.

(i) External Nodes are the nodes at which External Transactions settle. As appropriate and after consulting with Market Participants, the ISO will establish and re-configure External Nodes taking into consideration appropriate factors, which may include: tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices, and inter-regional trading impacts.

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer's knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer's company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer's annual load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of Real-Time Nodal Prices specified under Section III.2.5, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMSNR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve or local TMOR, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The unit-specific Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a ~~generating~~ Resource shall be determined for each ~~generating~~ Resource that the ISO ~~requires to reduce output~~re-dispatches in order to provide additional Operating Reserve or local TMOR and shall be equal to the difference between (i) the Real-Time Energy LMP at the ~~generation Node~~Location for the generating Resource, Demand Response Resource or Dispatchable Asset Related Demand Resource and (ii) the offer price associated with the ~~reduction of the generating~~re-dispatch of the Resource~~'s output~~ necessary to create the additional Operating Reserve or local TMOR from the ~~generating~~ Resource's expected output, consumption, or demand reduction level if it had been dispatched in economic merit order.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the LP algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

Requirement	Requirement Sub-Category	RCPF
Local TMOR		\$250/MWh
System TMOR	minimum TMOR	\$1000/MWh
	Replacement Reserve	\$250/MWh
System TMNSR		\$1500/MWh
System TMSR		\$50/MWh

The RCPFs shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve Requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed every five minutes, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour to be used in settlements.

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes within the New England Control Area, which Nodes shall be identified by the ISO on its internet website. The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

(i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;

(ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;

(iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;

(iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and

(v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.

(b) The ISO shall calculate and publish hourly Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation clearing prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices as soon as practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the

Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area; provided that Section III.E2.9 sets forth the Day-Ahead Energy Market and Real-Time Energy Market settlement rules for Demand Response Resources.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

(a) For each Market Participant for each hour, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the ~~ISO~~ Day-Ahead Energy Market as follows:~~. To accomplish this, the ISO will perform calculations to determine the following.~~

(i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each hour a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.

(ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each hour a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its generation Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.

(iii) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each hour a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.

(iv) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each hour a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation at that Location

(b) For each Market Participant for each hour, the ISO will determine a Real-Time Energy Market position. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each hour a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each hour a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by generating Resources, External Resources, and External Transaction purchases at that Location.

(iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each hour a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange** – Each Market Participant shall have for each hour a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation –** Each Market Participant shall have for each hour a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue.

(c) For each Market Participant for each hour, the ISO will determine the difference between the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)) and the Real-

Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each hour a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each hour a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each hour a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each hour a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between the Real-Time Locational Adjusted Net Interchange and the Day-Ahead Locational Adjusted Net Interchange.

(d) For each Market Participant for each hour, the ISO will determine Day-Ahead Energy Market monetary positions representing a charge or credit for its net purchases from or sales to the ISO Day-Ahead Energy Market. The Day-Ahead Energy Market Energy Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Energy Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

(e) For each Market Participant for each hour, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market. The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that hour multiplied by the Energy Component of the Real-Time Locational Marginal Prices for that hour. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that hour multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices for that hour.

The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that hour multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices for that hour.

(f) For each hour, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Congestion Charge/Credits.

(g) For each hour, the ISO will determine the excess or deficiency in loss revenue associated with the Day-Ahead Energy Market. The Day-Ahead Loss Revenue shall be equal to the sum of all Market Participants' Day-Ahead Energy Market Energy Charge/Credits and Day-Ahead Energy Market Loss Charge/Credits.

(h) For each hour for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(g)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(i) For each hour, the ISO will determine the excess or deficiency in loss revenue associated with the Real-Time Energy Market. The Real-Time Loss Revenue shall be equal to the sum of all Market

Participants' Real-Time Energy Market Deviation Energy Charge/Credit and Real-Time Energy Market Deviation Loss Charge/Credit plus Non-Market Participant Transmission Customer loss costs. The ISO will then adjust Real-Time Loss Revenue to account for Inadvertent Energy Revenue, as calculated under Section III.3.2.1(k) and Emergency transactions as described under Section III.4.3(a).

(j) Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each hour multiplied by the difference between the Loss Component of the hourly Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the hourly Real-Time Price at the source point or New England Control Area boundary source interface.

(k) For each hour, the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at each External Node by the associated Real-Time Locational Marginal Price and then summing these values for all External Nodes.

(l) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(k)). The Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations and Real-Time Generation Obligations over all Locations, measured as absolute values.

(m) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Real-Time Loss Revenue (Section III.3.2.1(i)). The Real-Time Loss Revenue Charges or Credits shall be equal to the Real-Time Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

III.3.2.2 Regulation.

(a) Each Market Participant shall have an hourly Regulation obligation equal to its pro rata share of the New England Control Area Regulation requirements for the hour, based on the Market Participant's total Real-Time Load Obligation in the New England Control Area for the hour. A Market Participant that does not meet its hourly Regulation obligation through its own Resources shall be charged for Regulation dispatched by the ISO to meet such obligation at the Regulation Clearing Price determined in accordance with paragraph (e) of this Section, plus the amounts, if any, described in paragraph (d) and (k) of this Section.

(b) A Market Participant supplying Regulation at the direction of the ISO in excess of its hourly Regulation obligation shall be credited for Time-On-Regulation Megawatts at the higher of (i) the Regulation Clearing Price.

(c) A Market Participant supplying Regulation at the direction of the ISO shall receive a credit for Regulation Service Megawatts at the Regulation Clearing Price multiplied by the Capacity-to-Service Ratio. The Capacity-to-Service Ratio is described under Subsection (h).

(d) Each Market Participant shall be charged its pro rata share of the total Regulation Service Credits for the hour, based upon the Market Participant's total Real-Time Load Obligation in the New England Control Area for the hour.

(e) The Regulation Clearing Price shall be determined by the ISO. The Regulation Clearing Price for each hour shall be equal to the time weighted average of all interval-based Regulation Clearing Prices calculated within the hour. The Regulation Clearing Price for each interval within the hour shall be equal to the highest Regulation Supply Offer price inclusive of the Regulation Opportunity Cost as calculated under III.3.2.2(i) of any generating Resources selected to provide Regulation in that interval. Regulation Clearing Prices shall be posted and finalized by the ISO in accordance with Seciton III.2.9A of this Market Rule 1.

(f) A Market Participant's Regulation Service Megawatts shall be determined by the ISO. A Market Participant's hourly Regulation Service Megawatts for each generating Resource providing Regulation shall be equal to the sum of the absolute value of the generation movement, in megawatts, towards the Regulation set point, such movement calculated in four second intervals based upon the generating Resource's Automatic Response Rate.

(g) A Market Particpant's Time-on-Regulation Megawatts shall be determined by the ISO. A Market Participant's hourly Time-on-Regulation Megawatts for each generating Resource providing Regulation shall be equal to the Regulation capability provided multiplied by the minutes of Regulation provision in the hour, divided by sixty.

(h) The Capacty-to-Service Ratio shall be determined by the ISO. The Capacity-to-Service Ratio is the relationship between Regulation capability provided and Regulation Service Megawatts provided in an hour. Based on historical analysis, on average, one megawatt of Regulation capability will produce ten megawatts of Regulation Service Megawatts. Based on this relationship, the Capacity-to-Service Ratio shall initially be set equal to 0.1 such that the revenue associated with Time-on-Regulation Megawatts and Regulation Service Megawatts associated with a Resource providing Regulation shall be equally split. The revenue split assumption and the Capacity-to-Service Ration may be changed from time-to-time and such changes shall be filed with the Commission for approval.

(i) In determining the credit to a Market Participant that is selected to provide Regulation and that actively follows the ISO's Regulation signals and instructions, the unit specific Regulation Opportunity Cost of a generating Resource shall be determined for each hour that the ISO requires a generating Resource to provide Regulation and shall be equal to the product of (i) the deviation of the generating Resource's output necessary to follow the ISO's Regulation signals from the generating Resource's expected output level if it had been dispatched in economic merit order and (ii) the absolute value of the difference between the Real-Time Price at the generation Node for the generating Resource and the megawatt weighted average Supply Offer price for the energy associated with the deviation of the generating Resource's expected output level if it had been dispatched in economic merit order.

(j) If revenues from the Regulation Clearing Price are insufficient to cover a Market Participant's actual costs for providing Regulation during the hour, a make-whole payment is calculated at the end of each hour equal to the greater of zero and the Market Participant's actual cost of providing Regulation minus the Regulation Clearing Price revenues.

(k) Amounts credited for Regulation make-whole payments, as calculated in Section III.3.2.2(j), in an hour shall be allocated and charged to each Market Partcipant that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in MWh during that hour.

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(f) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) Hourly net costs in excess of Real-Time Prices attributable to the purchase of Emergency energy by the ISO from other Control Areas shall be allocated to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for Pool-Scheduled Resources not following ISO dispatch instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following ISO dispatch instructions and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, ~~generation~~ generating Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations.

(b) Hourly net revenues in excess of Real-Time Prices attributable to the sale of Emergency energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for Pool-Scheduled Resources following ISO dispatch instructions and Self-Scheduled generating Resources with dispatchable increments above their Self-Scheduled amounts following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, ~~generation~~ generating Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load or in such other manner as may be described in ISO New England Manual M-28 (Market Rule 1 Accounting). Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6 and Section III.E2~~of this Market Rule 1~~, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

Non-Market Participant Transmission Customers shall be charged or credited for Congestion Costs as specified in Section III.1 of this Market Rule 1.

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time

Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 Eligible Data.

The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily Coincident Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

For revisions to meter data associated with assets that connect the New England Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the New England Control Area and the other Control Area to maintain an accurate record of inadvertent energy flow.

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

(b) Errors on the part of the ISO in the administration of Market Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the Correction Limit.

III.3.7 Eligibility for Billing Adjustments.

(a) Errors in Market Participant’s statements resulting from errors in settlement software, errors in data entry by ISO personnel, and settlement production problems, that do not affect the day-ahead schedule or real-time system dispatch, will be corrected as promptly as practicable. If errors are identified prior to the issuance of final statements, the market will be resettled based on the corrected information.

(b) Calculations made by scheduling or dispatch software, operational decisions involving ISO discretion which affect scheduling or real-time operation, and the ISO's execution of mandatory dispatch directions, such as self-schedules or external contract conditions, are not subject to retroactive correction and resettlement. The ISO will settle and bill the Day-Ahead Energy Market as actually scheduled and the Real-Time Energy Market as actually dispatched. Any post-settlement issues raised concerning operating decisions related to these markets will be corrected through revision of operations procedures and guidelines on a prospective basis.

(c) While errors in reporting hourly metered data may be corrected (pursuant to Section III.3.8), Market Participants have the responsibility to ensure the correctness of all data they submit to the market settlement system.

(d) Disputes between Market Participants regarding settlement of internal bilateral transactions shall not be subject to adjustment by the ISO, but shall be resolved directly by the Market Participants unless they involve an error by the ISO that is subject to resolution under Section III.3.7(a).

(e) Billing disputes between Market Participants and the ISO or Non-Market Participants and the ISO shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

(f) Criteria for Meter Data Errors to be eligible for a Requested Billing Adjustment. In order to be eligible to submit a Requested Billing Adjustment due to a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process, a Market Participant must satisfy one of the following two conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than thirty-six (36) days prior to the Correction Limit for Directly Metered Assets and no later than two (2) days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; or (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader and reported to the ISO by the Meter Data Error RBA Submission Limit, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per Asset over a calendar month. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website.

(b) Within three Business Days of the receipt by the ISO's Chief Financial Officer of an RBA form for a Meter Data Error, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Meter Data Error correction ("Notice of Meter Data Error Correction"), including, subject to the provisions of the ISO New England Information Policy, the specific details of the correction and the identity of the affected metering domains and the affected Host Participant Assigned Meter Readers. The "Notice of Meter Data Error Correction" shall identify a specific representative of the ISO to whom all communications regarding the matter are to be sent.

(c) In order for a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process to be eligible for correction, the Meter Data Error must satisfy one of the following conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than 36 days prior to the Correction Limit for Directly Metered Assets and no later than two days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per asset over a calendar month; and (3) if the Meter Data Error involves only Coincident Peak Contribution values, the average of the daily Meter Data Errors involving Coincident Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

(d) For a Meter Data Error, the Host Participant Assigned Meter Reader must submit to the ISO corrected meter data for Directly Metered Assets prior to the 46th calendar day after the Meter Data Error RBA Submission Limit. Corrected metered data for Profiled Load Assets and Coincident Peak Contribution values, must be submitted to the ISO by the Host Participant Assigned Meter Reader prior to the 87th calendar day after the Meter Data Error RBA Submission Limit. Corrected internal bilateral transactions data must be submitted to the ISO by a Market Participant prior to the 91st calendar day after the Meter Data Error RBA Submission Limit.

Any corrected data received after the specified deadlines is not eligible for use in the settlement process.

The Host Participant Assigned Meter Reader or Market Participant, as applicable, must confirm as part of its submission of corrected data that the eligibility criteria described in Section III.3.8(c) of Market Rule 1 have been satisfied.

To the extent that the correction of a Meter Data Error is for a Directly Metered Asset that affects multiple metering domains, all affected Host Participant Assigned Meter Readers or Assigned Meter Readers must notify the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit that the corrected Directly Metered Asset data is acceptable to them in order for the ISO to use the corrected data in the final settlement calculations. The Host Participant Assigned Meter Reader for the Directly Metered Asset is responsible for initiating an e-mail to every affected Host Participant Assigned Meter Reader or Assigned Meter Reader in order to obtain such acceptance and shall coordinate delivery of such acceptance to the ISO. The Host Participant Assigned Meter Reader for the Directly Metered Asset is also responsible for submitting all corrected and agreed upon Directly Metered Asset data to the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit.

(e) After the submission of corrected meter and internal bilateral transactions data, the ISO will have a minimum of 30 calendar days to administer the final settlement based on that data. Revised data will be used to recalculate all charges and credits, except that revised data will not be used to recalculate the PER adjustment, including the Hourly PER and Monthly PER values. Revised data will also not be used to recalculate Demand Resource Seasonal Peak Hours. The results of the final settlement will then be included in the next Invoice containing Non-Hourly Charges and the ISO will provide to the Chair of the NEPOOL Budget and Finance Subcommittee written notification that the final settlement has been administered.

III.8A Demand Response Baselines

Section III8.A shall govern Demand Response Baselines calculated for Capacity Commitment Periods commencing prior to June 1, 2017.

A Demand Response Baseline is calculated for any Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that requires a baseline on a daily basis using five-minute meter data.

8A.1 Establishing the Initial Demand Response Baseline

The Demand Response Baseline for a new Real-Time Demand Response Asset or Real-Time Emergency Generation Asset (an asset with no previously computed Demand Response Baseline) shall be the simple average of meter data for the asset for each five-minute interval from the initial ten non-Demand Response Holiday weekdays. The initial ten non-Demand Response Holiday weekdays of meter data used to establish the Demand Response Baseline shall consist of the first ten consecutive non-Demand Response Holiday weekdays with a complete set of interval meter data. A Market Participant may not submit Demand Reduction Offers until the month following the initial establishment of a Demand Response Baseline for an asset.

If two or more existing Real-Time Demand Response Assets (assets registered with the ISO with previously computed Demand Response Baselines) located at or behind the same retail delivery point are consolidated into one Real-Time Demand Response Asset located at the retail delivery point, or a significant change in load, generation, or reported meter data at an existing Real-Time Demand Response Asset or Real-Time Emergency Generation Asset occurs, a new initial Demand Response Baseline must be established for the asset.

8A.2 Establishing the Demand Response Baseline for the Next Day

If, for a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

(a) the asset has been dispatched or audited in the present day pursuant to Section III.13, or;
(b) the Demand Reduction Offer associated with the asset is eligible in the present Operating Day for payments pursuant to Section III.E1.9, or;
(c) the present day is a Demand Response Holiday, Saturday or Sunday, then:

the asset's Demand Response Baseline, in each five-minute interval, for the next day is equal to the Demand Response Baseline, in the same five-minute interval from the present day.

8A.3 Determining if Meter Data From the Present Day is Used in the Demand Response Baseline for the Next Day

If, for a Real-time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

(a) the present day is not a Demand Response Holiday, Saturday or Sunday, and; the asset has not been dispatched or audited in the present day pursuant to Section III.13, and; the Demand Reduction Offer associated with the asset is not eligible in any hour of the present day for payments pursuant to Section III.E1.9, or;

(b) the present day is not a Demand Response Holiday, Saturday or Sunday and more than seven of the prior 10 non-Demand Response Holiday weekdays have established a Demand Response Baseline determined pursuant to Section III.8A.2; then:

the asset's Demand Response Baseline in each five-minute interval, for the next day is calculated as the sum of 0.9 times the asset's Demand Response Baseline established for the present day in the same five-minute interval and 0.1 times the asset's meter data in the same five-minute interval from the present day.

8A.4 Baseline Adjustment

8A.4.1 Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets Without Generation or From Real-Time Emergency Generation Assets Without Additional Generation

For each day the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between the asset's actual metered demand and its Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response

Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load.

8A.4.2 Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets with Generation or From Real-Time Emergency Generation Assets With Additional Generation

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between the sum of the asset's actual metered demand and the output of all generators, or for Real-Time Emergency Generation Assets all additional generators, located behind the asset's end-use customer meter in the same time intervals and the asset's Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Facility Load.

8A.4.3 Baseline Adjustment for Real-Time Demand Reductions Produced By Directly Metered Generation

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset that is comprised of a Distributed Generation asset located behind the end-use customer meter of an individual end-use customer facility, the asset's Demand Response Baseline shall not be subject to the baseline adjustment.

8A.4.4 Baseline Adjustment for Real-Time Demand Reductions Produced by a Real-Time Demand Response Asset Located At a Retail Delivery Point Where There Are No Other Real-Time Demand Response Assets At or Behind that Retail Delivery Point

For a Real-Time Demand Response Asset located at a retail delivery point with no other Real-Time Demand Response Assets at or behind the same retail delivery point, the metered output of any Real-Time Emergency Generation Assets in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response

Asset's Demand Response Baseline. Each generator located behind an individual end-use customer's retail delivery point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between (1) the sum of the asset's actual metered demand as measured at the asset's retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the asset's retail delivery point in the same time intervals, and (2) the asset's Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, for assets that cannot produce net supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Facility Load. For assets that can produce net supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than the maximum ~~hourly~~ amount (MW) that the asset is allowed to push back into the electric system per the applicable generator interconnection agreement (where the amount (MW) pushed back into the electric system is a negative value) and shall not exceed the asset's Maximum Facility Load.

The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval minus the sum of the metered demand measured at the retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of any Real-Time Emergency Generation Assets is greater than its adjusted Demand Response Baseline.

8A.5 Establishing the Demand Response Baseline for a Day with a Scheduled or a Forced Curtailment

8A.5.1 Notification of Forced and Scheduled Curtailments

A Market Participant, with a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset for which a Demand Response Baseline measured at the retail delivery point is utilized, may notify the ISO of a forced curtailment for any reductions in demand that occur as a result of actions outside the control of the Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that is subject to the forced curtailment.

A Market Participant may notify the ISO of a scheduled curtailment at least seven calendar days before the start of any reductions in a Real-Time Demand Response Asset's demand or a Real-Time Emergency Generation Asset's demand where a Demand Response Baseline measured at the retail delivery point is utilized, that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Real-Time Demand Response Assets or Real-Time Emergency Generation Assets with a Maximum Interruptible Capacity ~~and/or Maximum Net Supply~~ of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The length of a scheduled curtailment must be a minimum of a single calendar day and may not exceed a total of 14 calendar days per Capacity Commitment Period.

8A.5.2 Submitting Meter Data Values for Days with Forced or Scheduled Curtailments

For each calendar day on which a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset where a Demand Response Baseline measured at the retail delivery point is utilized, is on a forced or scheduled curtailment, the asset's Demand Designated Entity shall submit to the ISO meter data values equal to the unadjusted baseline calculated for the first day of the forced or scheduled curtailment for all intervals excluding those in which the Real-Time Demand Response Resource with which the Real-Time Demand Response Asset is associated, or the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13, and excluding those in which a Demand Reduction Offer associated with the Real-Time Demand Response Asset had cleared day-ahead or became eligible in real-time pursuant to Section III.E1 on a day with an unanticipated forced curtailment.

8A.5.3 Performance Assessment for Days with Forced or Scheduled Curtailments

To assess the performance of Real-Time Demand Response Assets and Real-Time Emergency Generation Assets that are on a forced or scheduled curtailment, actual meter data values shall be submitted to the ISO for intervals during which the Real-Time Demand Response Resource with which the Real-Time Demand Response Asset is associated, or the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13, and intervals in which a Demand Reduction Offer associated with the Real-Time Demand Response Asset was cleared day-ahead or became eligible during the Operating Day pursuant to Section III.E1 on a day with an unanticipated forced curtailment.

III.8B Demand Response Baselines

Section III.8B shall govern Demand Response Baselines calculated for Capacity Commitment Periods commencing on or after June 1, 2017.

A Demand Response Baseline is calculated in 5-minute intervals for each Demand Response Asset and each Real-Time Emergency Generation Asset that is metered at the Retail Delivery Point for the following day types:

(a) weekdays (Monday-Friday) that are non-Demand Response Holidays;
(b) Saturdays, and;
(c) Sundays (including Demand Response Holidays).

8B.1 Demand Response Baseline Calculations

If a Demand Response Asset's metered demand represents Net Supply in an interval, that Net Supply ~~the Demand Response Asset's metered demand in the interval will be set equal to zero and that zero demand value~~ will be used in the Demand Response Baseline calculations for that interval pursuant to Sections III.8B.2 and III.8B.4.

8B.1.1 Demand Response Baseline Real-Time Emergency Generation Asset Adjustment

To the extent a Real-Time Emergency Generation Asset is located at the same Retail Delivery Point as a Demand Response Asset, the metered output of the Real-Time Emergency Generation Asset, in each five-minute interval, shall be added to the metered demand measured at the Retail Delivery Point in the same intervals for purposes of determining the Demand Response Asset's Demand Response Baseline.

8B.2 Establishing an Initial Demand Response Baseline and Resetting a Baseline

An initial Demand Response Baseline will be established for a Demand Response Asset with no previously computed Demand Response Baseline, and for a Real-Time Emergency Generation Asset with no previously computed Demand Response Baseline when a Demand Response Baseline measured at the Retail Delivery Point is utilized for the asset. A Demand Response Baseline will be reset using the initial baseline calculation methodology set forth below when a significant change in load, generation, or reported meter data at an existing Demand Response Asset or Real-Time Emergency Generation Asset occurs.

The initial Demand Response Baseline, or a reset of a Demand Response Baseline, ~~for a Demand Response Asset or Real-Time Emergency Generation Asset that is metered at the Retail Delivery Point with no previously computed Demand Response Baseline~~ shall be the simple average of metered demand data for the asset for each five-minute interval, subject to the conditions in Section III.8B.1, from the initial 10 days of the same day type. The initial 10 days of meter data used to establish the Demand Response Baseline shall consist of the first 10 consecutive days of the same day type with a complete set of interval meter data.

A Market Participant may not submit Demand Reduction Offers for a Demand Response Resource for a given day type until 1) the month following the establishment of the initial baseline by at least one Demand Response Asset mapped to the Demand Response Resource, provided that the initial baseline was established prior to the last calendar week of the month or, 2) two months following the establishment of the initial baselines for at least one Demand Response Asset mapped to the Demand Response Resource. This condition applies when establishing an initial Demand Response Baseline but not when resetting a Demand Response Baseline.
~~A Market Participant may not submit Demand Reduction Offers for a given day type until the month following the initial establishment of the Demand Response Baseline of the same day type for a Demand Response Asset.~~

8B.3 Establishing a Demand Response Baseline for the Next Day

If, for a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for a day type and the asset is associated with a Demand Response Resource that has been dispatched or audited in the present day pursuant to Section III.E2.5 or Section III.13~~ or Section III.E2.5~~, the Demand Response Baseline of the Demand Response Asset or Real-Time Emergency Generation Asset, in each five-minute interval, for the next day of the same day type is equal to the Demand Response Baseline of that Demand Response Asset or Real-Time Emergency Generation Asset, in the same five-minute interval from the present day.

8B.4 Determing if Meter Data from the Present Day is Used in the Demand Response Baseline for the Next Day of the Same Day Type

If, for a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for that day type, the Demand Response Resource or Real-Time Emergency Generation Resource to which the asset is associated has not been dispatched or audited in the present day pursuant to Section III.E2.5 or Section III.13 ~~or Section III.E2.5~~, or more than seven of the prior 10 days of the same day type have a Demand Response Baseline determined pursuant to Section III.8B.3, then ~~:~~

the Demand Response Baseline of the Demand Response Asset or Real-Time Emergency Generation Asset in each five-minute interval, for the next day of the same day type as the present day, is calculated as the sum of 0.9 times the Demand Response Baseline of that Demand Response Asset or Real-Time Emergency Generation Asset for the present day in the same five-minute interval and 0.1 times the Demand Response Asset's or Real-Time Emergency Generation Asset's meter data, subject to the conditions in Section III.8B.1, in the same five-minute interval from the present day.

8B.5 Baseline Adjustment

The Demand Response Baseline for each Demand Response Asset and each Real-Time Emergency Generation Asset is updated approximately every quarter hour by an adjustment factor that is calculated in accordance with this Section III.8B.5, which may increase or decrease the baseline.

(a) An adjustment factor is calculated if the resource with which the asset is associated is not in a period of dispatch (as defined by the resource's Dispatch Instruction including the Demand Response Resource Start-Up Time and Demand Response Resource Notification Time). The adjustment factor is calculated with real-time telemetry data in Real-Time and is calculated with revenue quality metering data for settlement purposes.

(b) For an asset that is part of a resource that is not in a period of dispatch, the adjustment factor is calculated using five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the start of the quarter hour. For an asset that is part of a resource that has received a Dispatch Instruction, the adjustment factor is calculated using five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the Dispatch Instruction was issued. After completion of a dispatch, the adjustment factor for an asset will be calculated using the five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the Dispatch Instruction was issued, until sufficient time has elapsed to calculate the adjustment using post-dispatch interval data.

(c) ~~For each day that a Demand Response Resource associated with a Demand Response Asset is scheduled in the Day-Ahead Energy Market or that a Demand Response Resource associated with a Demand Response Asset is dispatched in Real-Time for a demand reduction amount greater than zero, the ISO will calculate an~~ For a Demand Response Asset, the adjustment factor is equal to the average difference (MW) between the Demand Response Asset's telemetered or metered demand, which shall be adjusted pursuant to Section III.8B.1.1 (inclusive of any Net Supply), and its Demand Response Baseline during ~~in~~ the three intervals ~~during the two-hour period for Demand Response Resources beginning two hours plus the Demand Response Resource Start-Up Time prior to the start of the first interruption interval in the present day~~. For ~~each day that a Real-Time Emergency Generation Resource associated with~~ a Real-Time Emergency Generation Asset the ~~is dispatched in Real-Time for a demand reduction amount greater than zero, the ISO will calculate an~~ adjustment factor is equal to the ~~averge~~ average difference (MW) between the Real-Time Emergency Generation Asset's telemetered or metered demand and its Demand Response Baseline ~~in~~ during the three intervals ~~during the two-hour period for Real-Time Emergency Generation Resource beginning 2.5 hours prior to the start of the first interruption interal in the present day~~.

~~(a)~~(d) ~~The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However,~~ For Demand Response Assets that cannot produce Net Supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the ~~facility's~~asset's Maximum Load. For Demand Response Assets that can produce Net Supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than the maximum amount (MW) that the asset is allowed to push back into the electric system per the applicable generator interconnection agreement (where the amount (MW) pushed back into the electric system is a negative value) and shall not exceed the asset's Maximum Facility Load.~~For purposes of establishing the adjusted Demand Response Baseline, if a Demand Response Asset's metered demand represents Net Supply, the Demand Response Asset's metered demand in the interval will be set equal to zero.~~

8B.6 Establishing the Demand Response Baseline for a Day with a Scheduled or a Forced Curtailment

8B.6.1 Notification of Forced and Scheduled Curtailments

A Market Participant, with a Demand Response Asset or a Real-Time Emergency Generation Asset for which a Demand Response Baseline measured at the Retail Delivery Point is utilized, may notify the ISO of a forced curtailment for any reductions in demand that occur as a result of actions outside the control of the Demand Response Asset or Real-Time Emergency Generation Asset that is subject to the forced curtailment.

A Market Participant may notify the ISO of a scheduled curtailment at least seven calendar days before the start of any reductions in a Demand Response Asset's demand or a Real-Time Emergency Generation Asset's demand where a Demand Response Baseline measured at the Retail Delivery Point is utilized, that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Demand Response Assets or Real-Time Emergency Generation Assets with a Maximum Interruptible Capacity of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The length of a scheduled curtailment must be a minimum of a single calendar day and may not exceed a total of 14 calendar days per Capacity Commitment Period.

III.8B.6.2 Submitting Meter Data Values for Days with Forced or Scheduled Curtailments

For each calendar day on which a Demand Response Asset or a Real-Time Emergency Generation Asset, where a Demand Response Baseline measured at the Retail Delivery Point is utilized, is on a forced or scheduled curtailment pursuant to Section III.8B.6.1, the asset's Demand Designated Entity shall submit to the ISO meter data values equal to the unadjusted baseline calculated for the first day of the forced or scheduled curtailment for all intervals excluding those in which:

(a) the Demand Response Resource with which the Demand Response Asset is associated was dispatched during the period of a Shortage Event as defined in Section III.13.7.1.1.1 for the Capacity Zone in which the resource is located,

(b) the Demand Response Resource with which the Demand Response Asset is associated was dispatched in Real-Time pursuant to Section III.E2 on the first day of an unanticipated forced curtailment, or

(c) the Real-Time Emergency Generation Resource with which the Real-Time Emergency Genertion Asset is associated, was dispatched to reduce demand pursuant to Section III.13.

III.8B.6.3 Performance Assessment for Days with Forced or Scheduled Curtailments

To assess the performance of Demand Response Assets and Real-Time Emergency Generation Assets that are on a forced or scheduled curtailment, actual meter data values shall be submitted to the ISO for intervals during which:

(a) the Demand Response Resource with which the Demand Response Asset is associated was dispatched during the period of a Shortage Event as defined in Section III.13.7.1.1.1 for the Capacity Zone in which the Resource is located,

(b) the Demand Response Resource with which the Demand Response Asset is associated was dispatched in Real-Time pursuant to Section III.E2 on the first day of an unanticipated forced curtailment, or

(c) the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13.

III.9 Forward Reserve Market

The Forward Reserve Market is a market to procure TMNSR and TMOR on a forward basis to satisfy forward TMNSR and TMOR requirements.

III.9.1 Forward Reserve Market Timing.

A Forward Reserve Auction will be held approximately two months in advance of each Forward Reserve Procurement Period. The Forward Reserve Auction input parameters and assumptions will be evaluated, published and reviewed with Market Participants prior to the Forward Reserve Auction.

The Forward Reserve Procurement Periods shall be the Winter Capability Period (October 1 through May 31) or the Summer Capability Period (June 1 through September 30), as applicable.

The Forward Reserve Delivery Period shall be hour ending 0800 through hour ending 2300 for each weekday of the Forward Reserve Procurement Period excluding those weekdays that are defined as NERC holidays.

III.9.2 Forward Reserve Market Reserve Requirements.

The ISO shall conduct an advance purchase of capability to satisfy the expected Forward Reserve requirements for the system and each Reserve Zone as calculated by the ISO in accordance with the following procedures and as specified more fully in the ISO New England Manuals. The Forward Reserve Market reserve requirements will be specified as part of the Forward Reserve Auction parameters and will be published and reviewed with Market Participants prior to each Forward Reserve Auction.

III.9.2.1 Forward Reserve Market Reserve Requirements.

The Forward Reserve Market requirements for the New England Control Area will be based on the forecast of the first and second contingency supply losses for the next Forward Reserve Procurement Period and will consist of the following:

(i) One half of the forecasted first contingency supply loss will be specified as the minimum TMNSR to be purchased,

(ii) An additional amount of TMNSR will be added to the minimum TMNSR if system conditions forecasted for the Forward Reserve Procurement Period indicate that the TMNSR available during the period would otherwise be insufficient to meet Real-Time Operating Reserve requirements. The additional amount of TMNSR shall be calculated to account for: (a) any historical under-performance of Resources dispatched in response to a System contingency and (b) the likelihood that more than one half of the forecasted first contingency supply loss will be satisfied using TMNSR.

(iii) One half of the second contingency supply loss will be specified as the minimum TMOR to be purchased,

(iv) An amount of Replacement Reserve in the form of incremental TMOR will be specified in accordance with the Real-Time Replacement Reserve requirement as described in ISO New England Operating Procedure No. 8, Operating Reserve and Regulation and will be added to the minimum TMOR to be purchased.

The requirements specified above, further adjusted to respect the additional provisions described in Section III.9.2.2, represent the set of requirements that will be input into the Forward Reserve Auction.

III.9.2.2 Locational Reserve Requirements for Reserve Zones

Locational reserve requirements will be established for each Reserve Zone. The locational reserve requirements will reflect the need for 30-minute contingency response to provide 2nd contingency protection for each import constrained Reserve Zone. The locational reserve requirements can be satisfied only by Resources that are located within a Reserve Zone and that are capable of providing 30-minute or higher quality reserve products.

The ISO shall establish the locational reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each Reserve Zone for like Forward Reserve Procurement Periods. The ISO will commence the analysis on February 1 or the first business day thereafter for the subsequent summer Forward Reserve Procurement Period and on June 1 or the first business day thereafter for the subsequent winter Forward Reserve Procurement Period.

These daily peak hour requirements will be aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each Reserve Zone will establish the locational requirement.

In the event of a change in the configuration of the transmission system or the addition, deactivation or retirement of a major generating Resource, ~~or~~ Dispatchable Asset Related Demand~~,~~ or Demand Response Resource the rolling two-year historical analysis will be calculated in a manner that reflects the change in configuration of the transmission system or the addition, deactivation or retirement of a major generating Resource, ~~or~~ Dispatchable Asset Related Demand or Demand Response Resource as of the commencement date of the analysis provided that the following conditions are met:

(a) Change in Configuration of the Transmission System

Any change in the configuration of the transmission system must have been placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the locational reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the locational reserve requirements for the subsequent winter Forward Reserve Procurement Period.

If the change in the configuration of the transmission system consists of a new facility or upgrade of an existing facility, the facility must have operated at an availability level of at least 95% for the period beginning with its in service date and ending on January 31 prior to the summer Forward Reserve Procurement Period or ending on May 31 prior to the winter Forward Reserve Procurement Period.

(b) Addition, Deactivation or Retirement of a Major Generating Resource, ~~or~~ Dispatchable Asset Related Demand or Demand Response Resource.

For the addition of a new generating Resource, Dispatchable Asset Related Demand, or Demand Response Resource, the Resource must be placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the locational reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the locational reserve requirements for the subsequent winter Forward Reserve Procurement Period. For the deactivation or retirement of a generating Resource, ~~or~~ Dispatchable Asset Related Demand or Demand Response Resource, the Resource must have been removed from service on or before January 31 for inclusion in the analysis for setting the locational reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before May 31 for inclusion in the analysis for setting the locational reserve requirements for the subsequent winter Forward Reserve Procurement Period.

The modified historical data set will be composed of actual data used in the operation of the reconfigured system and historical (pre-reconfiguration) data adjusted for the impact of the system reconfiguration. Pre-reconfiguration data will be revised by substituting values from the historical data set that are no longer valid with corresponding values used in the operation of the reconfigured system.

The locational reserve requirements will be recalculated using the modified historical data set until the rolling two-year historical data set reflects a common system configuration.

III.9.3 Forward Reserve Auction Offers.

Forward Reserve Auction Offers for TMNSR and TMOR shall be (a) made on a $/MW-month basis, (b) made on a Reserve Zone specific basis, (c) made on a non-Resource specific basis and (d) shall be less than or equal to the Forward Reserve Offer Cap. Forward Reserve Auction Offers shall be submitted to the ISO by Market Participants. The Market Participants are responsible for complying with the requirements of this Section III.9 if the Forward Reserve Auction Offer is accepted.

III.9.4 Forward Reserve Auction Clearing and Forward Reserve Clearing Prices.

The Forward Reserve Auction shall simultaneously clear Forward Reserve Auction Offers to meet the Forward Reserve requirements for the system and each Reserve Zone using a mathematical programming algorithm. The objective of the mathematical programming based Forward Reserve Auction clearing is to minimize the total cost of Forward Reserve procured to meet the Forward Reserve requirements. The Forward Reserve Clearing Price for each Reserve Zone will reflect the cost to serve the next increment of reserve in that Reserve Zone based on the submitted offers. The Forward Reserve Auction algorithm substitutes higher quality TMNSR for lower quality TMOR to meet system or Reserve Zone TMOR requirements when it is economical to do so provided that no constraints are violated.

The Forward Reserve Auction algorithm shall also utilize excess Forward Reserve in one Reserve Zone to meet the Forward Reserve requirements of another Reserve Zone or the system provided that the Forward Reserve can be delivered such that no constraints are violated. In addition, the Forward Reserve Auction shall apply price cascading such that the Forward Reserve Clearing Price for TMOR in a Reserve Zone is always less than or equal to the Forward Reserve Clearing Price for TMNSR in that Reserve Zone. If there is insufficient supply to meet the Forward Reserve requirements for a Reserve Zone, the Forward Reserve Clearing Price for that Reserve Zone will be set to the Forward Reserve Offer Cap.

III.9.4.1 Forward Reserve Clearing Price and Forward Reserve Obligation Publication and Correction.

Market Participants with cleared Forward Reserve Auction Offers will receive a Forward Reserve Obligation for each Reserve Zone, as applicable, that is equal to the amount of Forward Reserve megawatts cleared for that Market Participant adjusted for internal bilateral transactions that transfer Forward Reserve Obligations.

(a) Within five business days after the close of the Forward Reserve Auctions, the ISO shall post Forward Reserve Clearing Prices and Forward Reserve Obligations, which shall be final as posted, not subject to correction or other adjustment, and used for the purposes of settlement, except as provided in subsections (c) and (d). The permissibility of correction of errors in sections of Market Rule 1 relating to settlement and billing processes shall not apply to Forward Reserve Clearing Prices and Forward Reserve Obligations deemed final pursuant to this Section III.9.4.1.

(b) Before posting the final Forward Reserve Clearing Prices and Forward Reserve Obligations, the ISO shall make a good faith effort when clearing those markets to discover and correct any errors that may occur due to database, software or similar errors of the ISO or its systems before publishing the final prices awarded.

(c) If the ISO determines based on reasonable belief that there may be one or more errors in the final Forward Reserve Clearing Prices and Forward Reserve Obligations or if no Forward Reserve Clearing Prices and Forward Reserve Obligations are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 11:59 p.m. of the third business day following the posting deadline specified in subsection (a), a notice that the Forward Reserve Clearing Prices and Forward Reserve Obligations are provisional and subject to correction or unavailable for initial publishing. The ISO shall confirm within three business days of posting a notice pursuant to this subsection whether there was an error in the Forward Reserve Clearing Prices and Forward Reserve Obligations and shall post a notice stating its findings.

(d) Within three business days after posting an initial notice pursuant to subsection (c); the ISO shall either: (1) publish final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations, or: (2) in the event that the ISO is unable to calculate and post final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations due to exigent circumstances not contemplated in this market rule, make an emergency filing with the Commission detailing the exigent circumstance which will not allow final Forward Reserve Clearing Prices and Forward Reserve Obligations to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

III.9.5 Forward Reserve Resources

III.9.5.1 Assignment of Forward Reserve MWs to Forward Reserve Resources.

(a) Prior to the close of the Re-Offer Period for each Operating Day of the Forward Reserve Procurement Period, Market Participants must convert their Forward Reserve Obligations into Resource-specific obligations by assigning Forward Reserve MWs to specific eligible Forward Reserve Resources, in accordance with procedures set forth in the ISO New England Manuals. The assignment of Forward Reserve MWs to a Forward Reserve Resource must be performed by the Lead Market Participant for the Resource.

(b) A Market Participant with a Forward Reserve Obligation must have an Ownership Share in a Forward Reserve Resource that is a generating Resource~~,~~ in order to assign Forward Reserve MWs to that Forward Reserve Resource to fulfill that Market Participant's Forward Reserve Obligation. If more than one Market Participant has an Ownership Share in a Forward Reserve Resource, the Forward Reserve MWs assigned to that Resource will be allocated pro-rata to Market Participants by Ownership Share.

III.9.5.2 Forward Reserve Resource Eligibility Requirements.

(a) Forward Reserve Resources are ~~off-line or on-line~~ Resources that have been assigned by Market Participants to meet their Forward Reserve Obligations. To be eligible as a Forward Reserve Resource, a Resource must satisfy the following criteria:

(i) ~~(i)~~ If the generating Resource is off-line, it must be a Fast Start Generator and have an audited CLAIM10 or CLAIM30 value established pursuant to Section III.9.5.3;

(ii) If the Resource is a Demand Response Resource which has not been dispatched, it must be a Fast Start Demand Response Resource and have an audited CLAIM10 or CLAIM30 value established pursuant to Section III.9.5.3;

(iii) If the generating Resource is expected to be on-line, or, for a Demand Response Resource, has been dispatched, during a Forward Reserve Delivery Period, it must be able to produce the energy or demand reduction equivalent to its assigned Forward Reserve Obligation within the timeframe of the assigned Forward Reserve Obligation when operating within its dispatch range;

(~~iii~~iv) If the Resource is an Asset Related Demand, it must have a CLAIM10 or CLAIM30 value established pursuant to Section III.9.5.3;

(~~i~~v) ~~The Resource may have a Capacity Supply Obligation for all, some, or none of its applicable Seasonal Claimed Capability.~~ Any portion of the Resource to which a Forward Reserve Obligation has been assigned that is without a Capacity Supply Obligation must not have been offered to support an External Transaction sale during the Operating Day for which it has been assigned;

(vi) The Resource must have Electronic Dispatch Capability;

(vii) The Resource must follow ~~ISO d~~Dispatch I~~i~~nstructions during the Operating Day. The Resource must meet the technical requirements associated with the provision of Forward Reserve as specified in ISO New England Operating Procedure No. 14, (Technical Requirements for Generators, Demand Resources and Asset Related Demands)~~Technical Requirements For Generation, Dispatchable and Interruptible Loads~~;

(viii) The portion of the Resource~~, with or without a Capacity Supply Obligation,~~ that is assigned a Forward Reserve Obligation for any portion of an Operating Day must be eligible to provide Operating Reserve in accordance with the provisions of Section III.10.1.1;

(~~vii~~ix) The portion of the Resource ~~without a Capacity Supply Obligation~~ to which a Forward Reserve Obligation has been assigned must be offered into the Real-Time Energy Market in accordance with the provisions of either Section III.13.6.1.1.2 or Section III.13.6.1.5.2.

(b) External Resources will be permitted to participate in the Forward Reserve Market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.9.5.3 Resource CLAIM10 and CLAIM30 Values.

III.9.5.3.1 Calculating Resource CLAIM10 and CLAIM30 Values.

1. The CLAIM10 or CLAIM30 value of a Resource shall equal:

   (a) the maximum output or demand-reduction level reached, including ~~output~~ the level reached during a CLAIM10 or CLAIM30 audit, measured at the 10 minute or 30 minute point from the Resource's receipt of an initial electronic startup Dispatch Instruction during the current Forward Reserve Procurement Period or the preceding like-season Forward Reserve Procurement Period, subject to the conditions in Section III.9.5.3.1.2 below;

   (b) multiplied by the Resource's then effective CLAIM10 or CLAIM30 performance factor established pursuant to Section III.9.5.3.3.

2. The value in Section III.9.5.3.1.1(a) is subject to the following additional conditions:

   (a) The value shall not include any dispatch in which the unit becomes unavailable within 60 minutes following the receipt of the initial Dispatch Instruction;

   (b) If the maximum output or demand-reduction level reached, as measured at the 10 minute or 30 minute point from the initial Dispatch Instruction, is greater than the highest Desired Dispatch Point issued for the Resource for that 10 minute or 30 minute period, the value shall be capped at the highest Desired Dispatch Point.

   ~~(c) For the first two Forward Reserve Procurement Periods following the effective date of this Section III.9.5.3.1, the calculation in Section III.9.5.3.1.1(a) shall use for the maximum output level reached in that previous like Forward Reserve Procurement Period: (i) for a Resource with a successful audit during the Forward Reserve Procurement Period, the audited CLAIM10 or CLAIM30 value in effect on the last day of the previous like Forward Reserve Procurement Period or (ii) for a Resource without a successful audit during the Forward Reserve Procurement Period, the value as determined in accordance with Section III.9.5.3.1.1.(a).~~

3. A Resource's CLAIM10 value shall be no greater than the Resource's CLAIM30 value.

4. The CLAIM10 or CLAIM30 value of a Resource shall be calculated and distributed to the Lead Market Participant weekly and shall become effective at 0001 of the Monday following the distribution.

III.9.5.3.2 CLAIM10 and CLAIM30 Audits.

(a) **General.** A ~~Lead~~ Market Participant ~~or Designated Entity~~ may request a CLAIM10 or CLAIM30 audit specifying the requested output or demand-reduction level that the Resource will attempt to reach in 10 or 30 minutes. A ~~Lead~~ Market Participant ~~or Designated Entity~~ may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(b) **CLAIM10 and CLAIM30 Audit Procedures.** The ISO will initiate a CLAIM10 or CLAIM30 audit by issuing an electronic Dispatch Instruction without providing prior notice to the ~~Lead~~ Market Participant~~ or Designated Entity~~. The ISO will normally perform the audit, at any time during the Forward Reserve Delivery Period, within five business days of receipt of the audit request or will advise the ~~Lead~~ Market Participant ~~or Designated Entity~~ if it will be unable to initiate the audit during the five business day period. The Resource's CLAIM10 or CLAIM30 audit value shall be the Resource's output or demand-reduction level reached at the 10 minute or 30 minute point after the receipt of the initial startup Dispatch Instruction.

III.9.5.3.3 CLAIM10 and CLAIM30 Performance Factors.

A Resource's CLAIM10 or CLAIM30 performance factor shall be established based upon the 10 most recent ISO-issued initial electronic startup Dispatch Instructions as described below. Dispatches greater than three years old shall not be used for the performance factor calculation. Resource performance factors will be calculated on a weekly basis.

(a) A Resource's performance factor is calculated as:

$$performance\ factor = \frac{\sum_{n=1}^{10}\left(\frac{resource\ output\ at\ 10\ or\ 30\ minutes_n\ (MW)}{resource\ target\ value_n\ (MW)} * n\right)}{\sum_{n=1}^{10} n}$$

$$performance\ factor = \frac{\sum_{n=1}^{10}\left(\frac{resource\ output\ or\ demand\ reduction\ at\ 10\ or\ 30\ minutes_n\ (MW)}{resource\ target\ value_n\ (MW)} * n\right)}{\sum_{n=1}^{10} n}$$

Where:

n is a value between 1 and 10, 1 representing the least recent dispatch signal, 10 representing the most recent dispatch signal;

the Resource output or demand reduction is measured at the 10 minute or 30 minute point from receipt of the initial startup Dispatch Instruction;

the Resource target value is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute or 30 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM10 or CLAIM30 value or (iii) the Resource's Offered CLAIM10 or Offered CLAIM30.

(b) For purposes of the performance factor calculation, the following conditions apply:

(i) For each CLAIM10 or CLAIM30 audit, the Resource's target value shall be set to the Resource's output or demand reduction at 10 or 30 minutes.

(ii) In the event the Resource has not had 10 electronic startup dispatches within the last three years, the "n" term in the performance factor calculation will be based on the number of startup dispatches that took place in the last three years, with the most recent dispatch having a weight of 10 and with the weighting decreasing by 1 for each previous startup dispatch.

(iii) If a Resource's output or demand reduction at 10 or 30 minutes is greater than the Resource's target value, then the Resource target value shall be set to the Resource output at 10 or 30 minutes.

(iv) A dispatch shall not be utilized in the performance factor calculation if a Resource starts and subsequently performs a normal shut down or ceases its demand reduction, in response to a Dispatch Instruction to shut down or, for a Demand Response Resource, in response to a Dispatch Instruction to cease its demand reduction, within the 10 or 30 minute period following the initial electronic startup Dispatch Instruction.

(v) Resource output or demand reduction at 10 or 30 minutes shall equal zero if the Resource becomes unavailable for dispatch within the 60 minute period following the initial electronic startup Dispatch Instruction.

III.9.5.3.4 Performance Factor Cure.

In the event a Resource either (a) is unable to reach at least 60% of the Resource target level, as reflected in the Dispatch Instruction issued for the Resource, either five times in a row or seven out of 10 times, as a result of a chronic operational problem with the Resource or (b) undergoes a major overhaul scheduled and performed during a planned outage that was approved in the ISO's annual maintenance scheduling process or during a scheduled curtailment for a Demand Response Resource, ~~the~~ a ~~Lead~~ Market Participant ~~or Designated Entity~~ may submit a restoration plan to the ISO to restore the Resource's CLAIM10 or CLAIM30 operational capability. Restoration plans submitted because of a Resource's inability to reach its target output or demand reduction shall indicate the specific nature of the problem, the steps to be taken to remedy the problem, and the timeline for completing the restoration. Restoration plans submitted for a major overhaul shall explain the actions taken during the planned outage or scheduled curtailment that would result in the increase of the Resource's CLAIM10 or CLAIM30. The ISO shall accept restoration plans that, upon review, indicate a reasonable likelihood of success in remedying the identified problem or, for a major overhaul, increasing the Resource's CLAIM10 or CLAIM30. Upon completion of the restoration, the ~~Lead~~ Market Participant ~~or Designated Entity~~ shall request a CLAIM10 or CLAIM30 audit of the Resource, using the procedures in Section III.9.5.3.2. Following the audit, the Resource's Performance Factor shall be set to 1.0, with all dispatches prior to the audit removed from the performance factor calculation.

III.9.6 Delivery of Reserve.

III.9.6.1 Dispatch and Energy Bidding of Reserve.

Forward Reserve shall be delivered by Forward Reserve Resources for an hour by offering the capability into the Real-Time Energy Market by submitting Supply Offers and Demand Bids no later than 30 minutes prior to the start of the operating hour at or above the Forward Reserve Threshold Price for the Operating Day. Day-Ahead Energy Market Supply Offers and Demand Bids for Resources to which Forward Reserve Obligations have been assigned will be used in the Real-Time Energy Market for the associated Operating Day even if the Supply Offers do not clear the Day-Ahead Energy Market, notwithstanding the requirements of ~~Market Rule 1~~ Section III.13.6.2.1.1.2, unless superseded by a more recent Supply Offer or Demand Bid submitted no later than 30 minutes prior to the start of the operating hour. A Market Participant is not required to submit a Supply Offer or Demand Bid into the Day-Ahead Energy Market for a Resource without a Capacity Supply Obligation in order for the Resource to be eligible to be a Forward Reserve Resource. The Forward Reserve Threshold Prices shall be set in accordance with the ISO New England Manuals so that Forward Reserve Resource capability has (a) a low probability of being dispatched for energy and (b) a high probability of being held for reserve purposes.

Forward Reserve shall be delivered by Forward Reserve Resources that are Demand Response Resources~~,~~ for an hour by offering the capability into the Real-Time Energy Market by submitting Demand Reduction Offers no later than the close of the Re-Offer Period at or above the Forward Reserve Threshold Price for the Operating Day. Day-Ahead Energy Market Demand Reduction Offers for Demand Response Resources to which Forward Reserve Obligations have been assigned will be used in the Real-Time Energy Market for the associated Operating Day even if the Demand Reduction Offers do not clear the Day-Ahead Energy Market, notwithstanding the requirements of Section III.13.6.1.5.2.

Forward Reserve Resources are scheduled and operated in accordance with Section III.1 of Market Rule 1; no distinction is made due to their status as Forward Reserve Resources. Forward Reserve Resources are eligible to set the Locational Marginal Price in accordance with Section III.2 of Market Rule 1.

III.9.6.2 Forward Reserve Threshold Prices.

The formula for determining the Forward Reserve Threshold Prices shall be fixed for the duration of the Forward Reserve Procurement Period. The ISO will reevaluate the Forward Reserve Threshold Price level for successive Forward Reserve Auctions on the basis of experience, expected operating conditions and other relevant information.

Forward Reserve Threshold Price: is calculated as the Forward Reserve Heat Rate multiplied by the daily Forward Reserve Fuel Index.

Forward Reserve Heat Rate: shall be fixed for the duration of the Forward Reserve Procurement Period and announced in the announcement for the Forward Reserve Auction. New Forward Reserve Heat Rates shall be specified for successive auctions, and shall be the lesser of: (a) the value determined in accordance with applicable ISO New England Manuals; or (b) the heat rate defined for the PER Proxy Unit in Section III.13.7.2.7.1.1.1(b) less 1 Btu/kWh.

Forward Reserve Fuel Index: is a daily fuel index, or combination of daily indices, applicable to the New England Control Area and specified in the announcement of the Forward Reserve Auction.

III.9.6.3 Monitoring of Forward Reserve Resources.

In accordance with Section III.A.13.4 ~~of ***Appendix A*** of this Market Rule 1~~, the Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Participant in accordance with ~~Market Rule 1, ***Appendix A***,~~ Section III.A.3. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4.

III.9.6.4 Forward Reserve Qualifying Megawatts.

Qualifying megawatts for generating Resources and Dispatchable Asset Related Demand are calculated separately on an hourly basis for Forward Reserve Resources supplying Forward Reserve from an off-line state and Forward Reserve Resources supplying Forward Reserve from an on-line state as follows:

Off-line qualifying megawatts. Off-line qualifying megawatts are the amount of capability equal to or below the Economic Maximum Limit for an off-line Forward Reserve Resource offered at or above the Forward Reserve Threshold Price. The generating Resource must satisfy this requirement in the Real-Time Energy Market. In the case of off-line Forward Reserve Resources, the calculation for Forward Reserve Qualifying Megawatts shall include both the energy Supply Offer and a pro-rated amount of Start-Up Fees and No-Load Fees as defined below.

An off-line Forward Reserve Resource must offer its capability so that the following holds:

$$\frac{StartUp}{EcoMax \times 1\ hour} + \frac{NoLoad}{EcoMax} + Energy\ Offer_{i} \geq ForwardReserveThresholdPrice$$

where:

StartUp = the generating Resource's cold Start-Up Fee.

NoLoad = the generating Resource's No-Load Fee.

$EnergyOffer_i$ = the generating Resource's Energy Offer for Energy Offer block $_i$.

EcoMax = the Economic Maximum Limit.

On-line qualifying megawatts: is the capability that is less than or equal to the Economic Maximum Limit and above the Economic Minimum Limit that is offered at or above the applicable Forward Reserve Threshold Price by an on-line generating Resource or, is the capability that is less than or equal to the Maximum Consumption Limit and greater than the Minimum Consumption Limit offered at or above the applicable Forward Reserve Threshold Price ~~by~~ for a Dispatchable Asset Related Demand ~~Resource~~. The Forward Reserve Resource must satisfy this requirement in the Real-Time Energy Market. For an on-line generating Resource that has been assigned to meet a Forward Reserve Obligation and has not cleared in the Day-Ahead Energy Market and is operating in a delivery hour as the result of an ISO commitment for VAR or local second contingency protection, the on-line qualifying megawatts shall be zero.

Qualifying megawatts for Demand Response Resources supplying Forward Reserve are calculated separately on an hourly basis for Demand Response Resources that have not been dispatched and Demand Response Resources that have been dispatched as follows:

Qualifying megawatts for a Demand Response Resource that has not been dispatched: is the amount of capability equal to or below the Maximum Reduction for the Demand Response Resource offered at or above the Forward Reserve Threshold Price. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. In the case of Demand Response Resources that have not been dispatched, the calculation for Forward Reserve Qualifying Megawatts shall include both the Demand Reduction Offer price and a pro-rated amount of the Interruption Cost as defined below.

A Demand Response Resource that has not been dispatched must offer its capability so that the following holds:

$$\frac{Interruption\ Cost}{MaxRed} + Energy\ Offer_i \geq Forward\ Reserve\ Threshold\ Price$$

where:

Interruption Cost = the amount, in dollars, that must be paid each time the Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

EnergyOffer$_i$ = the Resource's Demand Reduction Offer price for Energy Offer block $_i$.

Max Red = the Resource's Maximum Reduction x 1 hour.

Qualifying megawatts for a Demand Response Resource which has been dispatched: is the capability that is less than or equal to the Maximum Reduction and greater than the Minimum Reduction that is offered at or above the applicable Forward Reserve Threshold Price for the Demand Response Resource. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. For a Demand Response Resource which has been dispatched, has been assigned to meet a Forward Reserve Obligation, has not cleared in the Day-Ahead Energy Market, and is operating in a delivery hour as the result of an ISO commitment for local second contingency protection, the qualifying megawatts shall be zero.

III.9.6.5 Delivery Accounting.

Forward Reserve Delivered Megawatts are the quantity of Forward Reserve delivered in each hour of the Real-Time Energy Market to each Reserve Zone and is calculated as follows.

(a) Forward Reserve Delivered Megawatts for an off-line generating Forward Reserve Resource are calculated in megawatts for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount, in MW, of Forward Reserve that the off-line generating Resource can provide, based upon CLAIM10 and CLAIM30 values provided in the generating Resource's Real-Time Supply Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (energy at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(b) Forward Reserve Delivered Megawatts for an on-line generating Resource are calculated in megawatts for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramping rate of the on-line generating Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(c) Forward Reserve Delivered Megawatts for a Dispatchable Asset Related Demand are calculated ~~in megawatts~~ for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramp rate of the Resource, as applicable,

(ii) the amount of Forward Reserve capability specified in the Resource's CLAIM10 and CLAIM30 values,

(iii) Forward Reserve Assigned Megawatts, or

(iv) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2),

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(d) A Forward Reserve Resource's hourly Forward Reserve Delivered Megawatts for each Reserve Zone is calculated as the sum of the Market Participant's Resource specific hourly Forward Reserve Delivered Megawatts for each Reserve Zone.

(e) Resource specific Forward Reserve Delivered Megawatts for TMNSR within a Reserve Zone will be applied first to a Market Participant's higher value Forward Reserve Obligation for TMNSR in that Reserve Zone. Any surplus Forward Reserve Delivered Megawatts for TMNSR in that Reserve Zone will be applied to meet the Market Participant's Forward Reserve Obligation for TMOR in that Reserve Zone. Forward Reserve Delivered Megawatts remaining within that Reserve Zone after the Market Participant's Forward Reserve Obligation for that Reserve Zone have been met is available to be applied to the Market Participant's Forward Reserve Obligations in other Reserve Zones provided that the Forward Reserve Delivered Megawatts can be delivered to the other Reserve Zones.

(f) Forward Reserve Delivered Megawatts for a Demand Response Resource which has not been dispatched are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount of Forward Reserve that the Resource can provide, based upon CLAIM10 and CLAIM30 values provided in the Demand Response Resource's Demand Reduction Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (energy at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(g) Forward Reserve Delivered Megawatts for a Demand Response Resource which has been dispatched are calculated for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute Demand Response Resource Ramp Rate of that Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(h) In determining Forward Reserve Delivered Megawatts for Demand Response Resources the portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be multiplied by one plus the average avoided peak distribution losses.

(i) It will be assumed that all Demand Response Assets associated with a Demand Response Resource must first reduce their load from the electricity system before providing Net Supply.

(ii) The portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be the lesser of:

- Forward Reserve Delivered Megawatts, or
- The amount of load that the Demand Response Asset associated with a Demand Response Resource can reduce from the electric system as indicated from revenue quality meter data.

(iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with Net Supply will be capped at the Net Supply Limit.

III.9.7 Consequences of Delivery Failure.

III.9.7.1 Real-Time Failure-to-Reserve.

A Real-Time Forward Reserve Failure-to-Reserve 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.

(a) Forward Reserve Failure-to-Reserve Megawatts: A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMNSR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(i) Market Participant Forward Reserve Obligation for TMNSR for that Reserve Zone minus the Market Participant's Forward Reserve Delivered Megawatts for TMNSR for that Reserve Zone; and

(ii) Zero.

A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMOR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(i) Market Participant Forward Reserve Obligation for TMOR for that Reserve Zone minus Market Participant's Forward Reserve Delivered Megawatts for TMOR for that Reserve Zone; and

(ii) Zero.

(b) Forward Reserve Failure-to-Reserve Penalties: A Market Participant's Forward Reserve Failure-to-Reserve Penalty for a Reserve Zone in an hour is defined as:

(i) Forward Reserve Failure-to-Reserve Penalty for TMNSR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Reserve Penalty for TMOR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Reserve Penalty Rate (calculated for each Forward Reserve product and for each Reserve Zone) = maximum of (1.5 multiplied by the Forward Reserve Payment Rate for the Forward Reserve product, the applicable Real-Time Reserve Clearing Price for the Forward Reserve product in the Reserve Zone minus the Forward Reserve Payment Rate for the Forward Reserve product)

III.9.7.2 Failure-to-Activate Penalties.

Market Participants are required to pay a Forward Reserve Failure-to-Activate Penalty for each Forward Reserve Resource that fails to activate its Forward Reserve capability. For Forward Reserve Resources:

- providing TMNSR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction as part of the real-time contingency dispatch algorithm, or;
- providing TMOR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction when the ten-minute reserve requirement is binding or violated in an approved UDS case.

If a Market Participant's Forward Reserve Resource fails to activate Forward Reserve, which determination shall be made in accordance with subsection (a), that Market Participant shall be required to pay a Forward Reserve Failure-to-Activate Penalty associated with that Resource pursuant to subsection (b):

(a) **Forward Reserve Failure-to-Activate Megawatts**:

A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMNSR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(i) Maximum of Forward Reserve Delivered Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

(ii) Maximum of Target Activation Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMNSR from off-line Forward Reserve Resources or Demand Response Resources that are not dispatched, which are subsequently dispatched as part of the real-time contingency dispatch algorithm is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM10 or; (iii) the Resource's Offered CLAIM10.

Target Activation Megawatts for TMNSR from on-line Forward Reserve Resources dispatched, or Demand Response Resources that have been dispatched, as part of the real-time contingency dispatch algorithm is the lesser of: (i) the Resource's Manual Response Rate or Demand Response Resource Ramp Rate times 10 minutes or (ii) the Resource's Economic Maximum Limit or Maximum Reduction minus the Resource's initial output or demand reduction at activation, or; (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource's initial output or demand reduction at activation.

The actual amount of TMNSR energy delivered during activation is measured at the 10 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMNSR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMOR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(i) Maximum of Forward Reserve Delivered Megawatts for TMOR plus Forward Reserve Delivered Megawatts for TMNSR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

(ii) Maximum of Target Activation Megawatts for TMOR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMOR from off-line Forward Reserve Resources or Demand Response Resources that are not dispatched is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM30, or; (iii) the Resource's Offered CLAIM30.

Target Activation Megawatts for TMOR from on-line Forward Reserve Resources, or Demand Response Resources that have been dispatched, is the lesser of: (i) the Resource's Manual Response Rate or Demand Response Resource Ramp Rate times 30 minutes or (ii) the Resource's Economic Maximum Limit or Maximum Reduction minus the Resource's initial output or demand reduction at activation, or; (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial output or demand reduction at activation.

The actual amount of TMOR energy delivered during activation is measured at the 30 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMOR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

In determining the Target Activation Megawatts for Demand Response Resources, the portion of the Target Activation Megawatts not associated with Net Supply shall be multiplied by one plus the average avoided peak distribution losses.

The portion of the Target Activation Megawatts not associated with Net Supply is the lesser of:

- Target Activation Megawatts, or
- The amount of load reduced during activation.

The portion of the Target Activation Megawatts associated with Net Supply is the lesser of:

- Target Activation Megawatts less the Target Activation Megawatts not associated with Net Supply, or
- The amount of Net Supply that the Demand Response Resource produced during activation.

A Forward Reserve Resource that is a Fast Start Generator that fails to activate Forward Reserve through a failure to start , or a Forward Reserve Resource that is a Fast Start Demand Response Resource that fails to activate Forward Reserve through a failure to provide a demand reduction, shall have its Forward Reserve Delivered Megawatts set equal to zero in each subsequent hour in the applicable Forward Reserve Delivery Period until such time that the Market Participant notifies the ISO that the Forward Reserve Resource is capable of providing the Forward Reserve Delivered Megawatts.

(b) **Forward Reserve Failure-to-Activate Penalties:**

A Market Participant's Forward Reserve Failure-to-Activate Penalty for a Resource in an hour is defined as:

(i) Forward Reserve Failure-to-Activate Penalty for TMNSR = The sum of the Forward Reserve Payment Rate for TMNSR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Activate Penalty for TMOR = The sum of the Forward Reserve Payment Rate for TMOR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Activate Penalty Rate = Maximum of 2.25 multiplied by the Forward Reserve Payment Rate, or the applicable nodal LMP.

III.9.7.3 Known Performance Limitations.

The ISO may have reason to believe that a particular Forward Reserve Resource is frequently receiving, or may frequently receive, Forward Reserve payments for a portion or all of its capability that is not capable of activating the Forward Reserve Assigned Megawatts for TMNSR or the Forward Reserve Assigned Megawatts for TMOR. When the ISO believes there is such a limited Forward Reserve Resource, the ISO shall contact and confer with the affected Market Participant before taking any action.

(a) The ISO will, whenever practicable, contact the affected Market Participant of the Forward Reserve Resource to request an explanation of the relevant resource Offer Data;

(b) If the explanation, if available, considered together with other information available to the ISO, indicates to the satisfaction of the ISO that the questioned Forward Reserve payments are consistent with Forward Reserve Resource capabilities, no further action will be taken; and

(c) If no agreement is reached, or an acceptable explanation is not provided, the Market Participant may request a Resource performance audit~~ as specified in ISO New England Manuals~~. If the Forward Reserve Resource fails the performance audit or the Market Participant refuses to request a Resource performance audit, the ISO may take remedial action. Remedial actions may include, but are not limited to: (i) redeclaration, by the ISO, of any relevant operational Offer Data parameter, or (ii) removing the ~~asset~~ Resource or the relevant portion of the Resource's ~~asset's~~ capability to provide Forward Reserve on a going-forward basis.

III.9.8 Forward Reserve Credits.

Payment for Forward Reserve is based upon a Market Participant's Final Forward Reserve Obligation and the applicable Forward Reserve Clearing Prices. The ISO shall calculate these credits on an hourly basis for each Reserve Zone as follows:

(a) Final Forward Reserve Obligations for TMNSR and TMOR for each Market Participant are calculated for each Reserve Zone for each hour as follows:

(i) Final Forward Reserve Obligation = minimum [Forward Reserve Obligation, Forward Reserve Delivered Megawatts]

(b) $FCACP_{Zone}$ and $FRACP_{Zone}$ are defined as:

$FCACP_{Zone}$ for a Reserve Zone is the Forward Capacity Auction Capacity Clearing Price for the Capacity Zone in which the Reserve Zone is contained.

$FCACP_{Zone}$ for the Rest of System is the maximum Forward Capacity Auction Capacity Clearing Price for all Capacity Zones included in whole or in part in the Rest of System.

$FRACP_{Zone}$ is the Forward Reserve Clearing Price for the relevant Reserve Zone, for TMNSR or TMOR, respectively;

(c) Market Participant Forward Reserve Credit for TMNSR=Final Forward Reserve Obligation for TMNSR multiplied by the applicable hourly Forward Reserve Payment Rate for TMNSR;

where,

the hourly Forward Reserve Payment Rate for TMNSR is equal:

maximum of [(applicable monthly $FRACP_{Zone}$ for TMNSR – $FCACP_{Zone}$), 0] divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

(d) Market Participant Forward Reserve Credit for TMOR = Final Forward Reserve Obligation for TMOR multiplied by the applicable hourly Forward Reserve Payment Rate for TMOR; where,

the hourly Forward Reserve Payment Rate for TMOR is equal to:

maximum of [(applicable monthly $FRACP_{Zone}$ for TMOR - $FCACP_{zone}$),0] divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

III.9.9 Forward Reserve Charges.

Forward Reserve Charges are allocated to each Market Participant in two steps. The first step allocates the Forward Reserve Credits associated with the procurement of reserves to meet the Forward Reserve requirement for the system. The second step, if necessary, allocates any remaining Forward Reserve Credits.

III.9.9.1 Forward Reserve Credits Associated with System Reserve Requirement.

The portion of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is determined by simulating a Forward Reserve Auction using all submitted Forward Reserve Auction Offers to meet only the Forward Reserve Market minimum requirements for the New England Control Area pursuant to Section III.9.2.1. The simulated Forward Reserve Auction will clear offers pursuant to the methodology set forth in Section III.9.4 to calculate TMNSR and TMOR proxy system clearing prices. The TMNSR and TMOR proxy system clearing prices will reflect the cost to serve the next increment of reserve above the Forward Reserve Market minimum requirement for the New England Control Area.

For each hour, the total amount of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is calculated as the lesser of:

(i) The TMNSR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the maximum of the [TMNSR proxy system clearing price reduced by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, 0], plus the TMOR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the maximum of the [TMOR proxy system clearing price reduced by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, 0] and divided by the number of hours in the month associated with the Forward Reserve Delivery Period, or

(ii) Total Forward Reserve Credits for the New England Control Area as calculated pursuant to Section III.9.8.

III.9.9.2 Adjusting Forward Reserve Credits for System Requirement.

For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is reduced by:

(i) Any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in the Rest of System or in a Load Zone that is ineligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, and

(ii) A prorated amount of any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in a Load Zone that is eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.3 Allocating Forward Reserve Credits for System Requirements.

For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirements for the system as calculated pursuant to Section III.9.9.1, is reduced by any penalties calculated pursuant to Section III.9.9.2, and allocated on a pro rata basis using each Market Participant’s share of Real-Time Load Obligation in each Load Zone (which includes the Market Participant’s Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant’s Real-Time Reserve Designations associated with Dispatchable Asset Related Demands within that Load Zone.

III.9.9.4 Allocating Remaining Forward Reserve Credits.

For each hour, any Forward Reserve Credits not allocated pursuant to Section III.9.9.3 are allocated on a pro rata basis to each Market Participant's share of Real-Time Load Obligation in a Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Real-Time Reserve Designations associated with Dispatchable Asset Related Demands within that Load Zone) that meets the criteria in Section III.9.9.4.1. The allocation for each Load Zone is based on the ratio of the Forward Reserve Credits cleared in the Respective Reserve Zone for the Forward Reserve Credits cleared in all Reserve Zones that meet the criteria in Section III.9.9.4.1, and is reduced by:

(i) A prorated amount of any Forward Reserve Failure-to-Reserve Penalties or Forward Reserve Failure-to-Activate Penalties that occur in a Load Zone eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of the total Forward Reserve Credits less any Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.4.1 Allocation Criteria for Remaining Forward Reserve Credits.

If the following criteria are met, then a Market Participant with Real-Time Load Obligation in a Load Zone is eligible to receive any remaining Forward Reserve Credits not allocated pursuant to Section III.9.9.3.

(i) The Load Zone is encompassed in whole or in part in a Reserve Zone with a locational reserve requirement greater than zero, and

(ii) The Forward Reserve Clearing Price of a Reserve Zone is higher than the Forward Reserve Clearing Price of the Rest of System.

III.10 Real-Time Reserve

The ISO shall use a joint optimization dispatch algorithm to serve Real-Time Energy Market requirements and meet Real-Time Operating Reserve requirements based on a least-cost security constrained economic dispatch. The Real-Time dispatch algorithm will designate Resources to meet the Energy requirements and will designate Resources to meet the Operating Reserve requirements of the New England Control Area.

III.10.1 Provision of Operating Reserve in Real-Time

For each Market Participant for each hour, the ISO will determine each Market Participant's provision of Operating Reserve in Real-Time. To accomplish this, the ISO will perform calculations to determine the following.

III.10.1.1 Real-Time Reserve Designation

Each Market Participant shall have for each hour and for each eligible generating Resource capable of providing Operating Reserve a Real-Time Reserve Designation, in megawatts, equal to the amounts of Operating Reserve designated by the ISO to that Resource in Real-Time adjusted downward after-the-fact, if necessary, to account for differences in actual Resource output based upon revenue quality meter readings and the estimated Resource output utilized to determine the amount of Real-Time Reserve Designation. Each Market Participant shall have for each hour and for each eligible Asset Related Demand Resource or Demand Response Resource capable of providing Operating Reserve a Real-Time Reserve Designation, in megawatts, equal to the amounts of Operating Reserve designated by the ISO to that Resource in Real-Time adjusted downward after-the-fact, if necessary, to account for differences in actual Operating Reserve capability ~~Resource consumption~~ based upon revenue quality meter readings and the estimated ~~Resource consumption~~Operating Reserve capability utilized to determine the amount of Real-Time Reserve Designation. Resource eligibility to provide Operating Reserve shall be specified in the ISO New England Manuals.

III.10.2 Real-Time Reserve Credits

For each Market Participant for each hour, the ISO will determine a credit for provision of Operating Reserve in Real-Time.

(a) A Market Participant's Resource specific Real-Time Reserve Credit for TMSR shall be equal to that Market Participant's Resource specific Real-Time Reserve Designation for TMSR multiplied by the Real-Time Reserve Clearing Price for TMSR. The Real-Time Reserve Credit for TMSR associated with a

Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMSR in that Load Zone.

(b) A Market Participant's Resource specific Real-Time Reserve Credit for TMNSR shall be equal to that Market Participant's Resource specific Real-Time Reserve Designation for TMNSR multiplied by the Real-Time Reserve Clearing Price for TMNSR. The Real-Time Reserve Credit for TMNSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMNSR in that Load Zone.

(c) A Market Participant's Resource specific Real-Time Reserve Credit for TMOR shall be equal to that Market Participant's Resource specific Real-Time Reserve Designation for TMOR multiplied by the Real-Time Reserve Clearing Price for TMOR. The Real-Time Reserve Credit for TMOR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMOR in that Load Zone.

III.10.3 Real-Time Reserve Charges.

(a) For each hour, the ISO will ~~as~~ allocate the sum of the Real-Time Reserve Credits and Forward Reserve Obligation Charges for each Load Zone, calculated separately for TMSR, TMNSR and TMOR, to each Market Participant as follows:

Real-Time Reserve $Charge_{k,i}$ = [Reserve Charge Allocation $MW_{k,I}$] x [$RT\_CHRG\_RT_i$]

Where:

Real-Time Reserve $Charge_{k,i}$, is Market Participant *k's* Real-Time Reserve Charge for Load Zone *i* for all Real-Time reserve services and Forward Reserve Obligation Charges;

Reserve Charge Allocation MW = Market Participant *k's* Real Time Load Obligation in Load Zone *i* adjusted for Market Participant *k's* Dispatchable Asset Related Demand MWs in Load Zone *i* that are designated for Real-Time reserves.

$RT\_CHRG\_RT_i$ = [IRT_SUP_PMNT]/RT_P_WTD_LD_OB] x [RT_P_RATIO] for TMSR, TMNSR, or TMOR, as applicable.

RT_P_WTD_LD_OB = ∑[Reserve Charge Allocation MW_{si}] x [P_RATIO_i] for TMSR, TMNSR or TMOR, as applicable;

[RT_SUP_PMNT] = The total over all Load Zones of Real-Time Reserve Credits for TMSR, TMNSR or TMOR, plus the total over all Load Zones of the Forward Reserve Obligation Charges for TMNSR or TMOR, as applicable;

RT_P_RATIOi is the ratio of the Real Time Reserve Clearing Price in Load Zone i for TMSR, TMNSR or TMOR, as applicable, to the Real -Time Reserve Clearing Price in the Reference Zone for TMSR, TMNSR or TMOR, as applicable. To the extent that a Load Zone contains more than one Reserve Zone, that Load Zone's Real-Time Reserve Clearing Price for TMSR, TMNSR or TMOR shall be the Real-Time Reserve Designation weighted average of the Reserve Zone Real-Time Reserve Clearing Prices in that Load Zone for TMSR, TMNSR or TMOR, as applicable;

The Reference Load Zone is the Load Zone with the minimum, non-zero Real-Time Reserve Clearing Price for TMSR, TMNSR or TMOR, as applicable.

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Load Zone from which the External Transaction is exporting for the purpose of calculating Real-Time Reserve Charges. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

III.10.4 Forward Reserve Obligation Charges.

For each Market Participant with a Forward Reserve Obligation, the ISO will determine a Forward Reserve Obligation Charge for each hour such that a Market Participant will not receive compensation for the provision of both Real-Time Operating Reserve MWs and Forward Reserve MWs for the same reserve service.

III.10.4.1 Forward Reserve Obligation Charge Megawatts for Forward Reserve Resources.

The Forward Reserve Obligation Charge megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Forward Reserve Resource are equal to the lesser of the Forward Reserve Delivered MW or Real-Time Reserve Designation MW (where any demand reduction portion of Real-Time Reserve Designation MW is increased by average avoided peak distribution losses).

III.10.4.2 Forward Reserve Obligation Charge Megawatts.

The Forward Reserve Obligation Charge megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Market Participant is equal to the lesser of the sum of Forward Reserve Obligation Charge megawatts for all the Reserve Resources assigned by the Market Participant, or the Final Forward Reserve Obligation

III.10.4.3 Forward Reserve Obligation Charge.

The Forward Reserve Obligation Charge will be calculated as follows:

(a) A Market Participant's Forward Reserve Obligation Charge for TMNSR in each Reserve Zone shall be equal to the Market Participant's Forward Reserve Obligation Charge megawatts for TMNSR in that Reserve Zone multiplied by the Real-Time Reserve Clearing Price for TMNSR in that Reserve Zone.

(b) A Market Participant's Forward Reserve Obligation Charge for TMOR in each Reserve Zone shall be equal to the Market Participant's Forward Reserve Obligation Charge megawatts for TMOR in that Reserve Zone multiplied by the Real-Time Reserve Clearing Price for TMOR in that Reserve Zone.

SECTION III

MARKET RULE 1

STANDARD MARKET DESIGN

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III.13. Forward Capacity Market.

The ISO shall administer a forward market for capacity ("Forward Capacity Market") in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market ("Capacity Commitment Period"), the ISO shall conduct a descending clock auction ("Forward Capacity Auction") in accordance with the provisions of Section III.13.2 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 Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1. A Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (Section III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section III.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Resource, New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the financial assurance deposit described in Section III.13.1.9.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1.

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate 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) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than $200 per kilowatt of the whole resource's summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than $100 per kilowatt of the whole resource's summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.
The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output greater than 2 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, but less than or equal to the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section does not cause the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement, the Project Sponsor must submit a New Capacity Qualification Package but is not required to submit a New Capacity Show of Interest Form for the incremental amount by the New Capacity Qualification Deadline. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.3 causes the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement or MW amount approved pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), the Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.1.5. Treatment of Resources that are Partially New and Partially Existing.

For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.1.3 or Section III.13.1.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) 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), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline. 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), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

III.13.1.1.1.7 Renewable Technology Resources.

To participate in the Forward Capacity Market as a Renewable Technology Resource, a Generating Capacity Resource must satisfy the following requirements:

(a) receive an out-of-market revenue source supported by a state- or federally-regulated rate, charge or other regulated cost recovery mechanism;

(b) qualify as a renewable or alternative energy generating resource under any New England state's mandated (either by statute or regulation) renewable or alternative energy portfolio standards as in effect on January 1, 2014, or, in states without a standard, qualify under that state's renewable energy goals as a renewable resource (either by statute or regulation) as in effect on January 1,

2014. The resource must qualify as a renewable or alternative energy generating resource in the state in which it is geographically located;

(c) participate in a Forward Capacity Auction for a Capacity Commitment Period beginning on or after June 1, 2018 as a New Generating Capacity Resource pursuant to Section III.13.1.1, and;

(d) has been designated for treatment as a Renewable Technology Resource pursuant to Section III.13.1.1.2.9.

An Export De-List Bid or Administrative Export De-List Bid may not be submitted for Generating Capacity Resources that assumed a Capacity Supply Obligation by participating in a Forward Capacity Auction as a Renewable Technology Resource.

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.
For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also submit to the ISO an Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the financial assurance deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. Upon submission of the financial assurance deposit by the Project Sponsor pursuant to Section III.13.1.9.1, the resource is obligated to participate and will be included in the Forward Capacity Auction at its FCA Qualified Capacity amount at the Forward

Capacity Auction Starting Price. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, material changes (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein. The New Capacity Show of Interest Form is available on the ISO website. A New Capacity Show of Interest Form to which a material change has been made shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor's contact information; the Project Sponsor's ISO customer status; the project's expected Commercial Operation date; the project address or location, and if relevant, asset identification number; the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall have the same meaning as set forth in Schedule 22 or Schedule 23, as applicable, of Section II of the Transmission, Markets and Services Tariff. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must submit, with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall mean that: (i) the Project Sponsor is the owner in fee simple of the real property on which the project will be located; (ii) the Project Sponsor holds a valid written leasehold interest in the real property on which the project will be located; (iii) the Project Sponsor holds a valid written option, exercisable solely by the Project Sponsor or its assignee, to purchase or lease property on which the project will be located; or (iv) the Project Sponsor holds a duly executed written contract to purchase or lease the real property on which the project will be located. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits**. In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing**. In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders**. In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2.2(d) and that accounts for more than five percent of the total project cost.

(d) **Substantial Site Construction**. In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery**. In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing**. In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (d) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent Commercial Operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning**. In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation**. In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. Offer Information.

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity at or above the Economic Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity 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 the OATT.

III.13.1.1.2.2.4. Capacity Commitment Period Election.

In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) 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. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity. In addition to the information described elsewhere in this Section III.13.1.1.2.2:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource and Intermittent Settlement Only Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource or the Intermittent Settlement Only Resource.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a material change (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource's Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s), as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

(g) New Generating Capacity Resources, or portions thereof, shall not be considered to have met their Capacity Supply Obligation for the purposes of this Forward Capacity Market and shall not receive compensation if any upgrades to be completed by the Project Sponsor required to remove overlapping interconnection impacts as identified in (f) have not been completed, including, any upgrades identified in a restudy pursuant to Section 3.2.1.3 of Schedule 22 and Section 1.7.1.3 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff and, if necessary, requests for the interconnection of an Elective Transmission Upgrade, in time for the Capacity Commitment Period unless the Capacity Supply Obligation is appropriately covered.

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource's New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

(a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;

(b) whether the critical path schedule includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and

(e) whether, in the case of an Intermittent Power Resource or Intermittent Settlement Only Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a 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.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a 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 amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. [Reserved.]

III.13.1.1.2.7. Opportunity to Consult with Project Sponsor.

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor 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 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 believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor 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.

III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

(a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;

(b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource's New Capacity Qualification Package was not accepted;

(c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);

(d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource's summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;

(e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Generating Capacity Resource; (ii) for the notification to a Conditional Qualified New Generating Capacity Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Generating Capacity Resource, the Queue Position of the Conditional Qualified New Generating Capacity Resource; and

(f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal Market Monitor's determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.1.2.9 Renewable Technology Resource Election.

A Project Sponsor or Market Participant electing Renewable Technology Resource treatment for the FCA Qualified Capacity of a New Generating Capacity Resource shall submit a Renewable Technology Resource election form no later than five Business Days after the date on which the ISO provides qualification determination notifications pursuant to Section III.13.1.1.2.8. Only the portion of the FCA Qualified Capacity of the resource that meets the requirements of Section III.13.1.1.1.7 is eligible for treatment as a Renewable Technology Resource.

Renewable Technology Resource elections may not be modified or withdrawn after the deadline for submission of the Renewable Technology Resource election form.

III.13.1.1.2.10 Determination of Renewable Technology Resource Qualified Capacity.

(a) If the total FCA Qualified Capacity of Renewable Technology Resources exceeds the cap specified in subsections (b), (c) and (d) the qualified capacity value of each resource shall be prorated by the ratio of the cap divided by the total FCA Qualified Capacity. The ISO shall notify the Project Sponsor or Market Participant, as applicable, of the Qualified Capacity value of its resource no more than three Business Days after the deadline for submitting Renewable Technology Resource elections.

(b) The cap for the Capacity Commitment Period beginning on June 1, 2018 is 200 MW.

(c) The cap for the Capacity Commitment Period beginning on June 1, 2019 is 400 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior Capacity Commitment Period.

(d) The cap for each Capacity Commitment Period beginning on or after June 1, 2020 is 600 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior two Capacity Commitment Periods.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Resource or Existing Demand Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only

Resource's net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006 summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be established pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e).

(b) The Intermittent Power Resource's or Intermittent Settlement Only Resource's summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) 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 the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.

(a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in each of the previous winter periods, or portion thereof if the

Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.

(b) The Intermittent Power Resource's and Intermittent Settlement Only Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.2(a).

(c) 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 the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the two treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) [Reserved.]

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, and if accepted by the ISO shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

The Dynamic De-List Bid Threshold beginning with the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018) shall be $3.94/kW-month. The Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Dynamic De-List Bid Threshold shall be filed with the Commission under Section 205 of the Federal Power Act prior to the Existing Capacity Qualification Deadline for the associated Forward Capacity Auction.

III.13.1.2.3.1.1. Static De-List Bids.

An Existing Generating Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation at prices at or above the Dynamic De-List Bid Threshold during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section

III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests). Static De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.2. Permanent De-List Bids.

An Existing Generating Capacity Resource seeking to specify a price below which it would not accept a Capacity Supply Obligation permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource's full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource, an Intermittent Settlement Only Resource or a Renewable Technology Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource, an Intermittent Settlement Only Resource or a Renewable Technology Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity

Commitment Period. Administrative Export De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.

A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.

The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a resource that has a Permanent De-List Bid rejected by the Internal Market Monitor, a Non-Price Retirement Request may be submitted within 14 days after the resource receives notice of the rejection or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.

III.13.1.2.3.1.5.3. Reliability Review of Non-Price Retirement Requests.

The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

III.13.1.2.3.1.5.4. Obligation to Retire.

A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5.3(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.

III.13.1.2.3.1.6. Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. Internal Market Monitor Review.

The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

(i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.

(ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive de-listing of each individual asset in preferred de-list order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of bids as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The bids of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will reject the bid as described in Section III.13.1.2.3.2.1.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

For purposes of this Section III.13.1.2.3.2, a Static De-List Bid, Permanent De-List Bid, or Export Bid shall be associated with a pivotal supplier if, using the best available estimates of FCA Qualified Capacity available at that time: (1) at the Forward Capacity Auction Starting Price, the total amount of FCA Qualified Capacity of all Existing Capacity Resources in the New England Control Area minus the Installed Capacity Requirement (net of HQICCs) is less than or equal to the greater of:

(a) the amount of FCA Qualified Capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and

(b) the amount of FCA Qualified Capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW;

or (2) where the bid is associated with a resource in an import-constrained Capacity Zone, if at the Forward Capacity Auction Starting Price, the total amount of FCA Qualified Capacity of all Existing Capacity Resources in the import-constrained Capacity Zone minus the Local Sourcing Requirement for the import-constrained Capacity Zone is less than or equal to the greater of:

(a) the amount of FCA Qualified Capacity from all Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and

(b) the amount of FCA Qualified Capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 100 MW.

In making this determination, the total amount of FCA Qualified Capacity of all Existing Capacity Resources will be reduced by an amount equal to the total of all pending Non-Price Retirement Requests and Permanent De-List Bids other than those submitted by the Lead Market Participant for the resource being evaluated, and the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource will include any capacity subject to a pending Non-Price Retirement Request or Permanent De-List Bid. The determination whether a Lead Market Participant is pivotal will be included in the qualification determination notification described in Section III.13.1.2.4. If the applicable Installed Capacity Requirement (net of HQICCs) and Local Sourcing Requirement are not finalized at the time that the Internal Market Monitor must make this determination, then the Internal Market Monitor shall use the best available estimates of those values available at that time, and shall publish those estimated values to the ISO website no later than the date that the qualification determination notifications are issued.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids the Dynamic De-List Bid Threshold, and Permanent De-List Bids Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid, each Export Bid above the Dynamic De-List Bid Threshold, and each Permanent De-List Bid above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) The Existing Generating Capacity Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); (3) reasonable risk premium assumptions (as determined pursuant to Section III.13.1.2.3.2.1.4); and (4) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). Sufficient documentation and information about each of these bid components must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments and risk premiums, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate. The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

III.13.1.2.3.2.1.1.1. Review of Permanent De-List Bids and Export Bids.

(a) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(b) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(c) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, reasonable expectations about the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.1(c), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor. The Lead Market Participant for such a resource may elect to have the ISO-determined bid entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b) by so indicating in a filing with the Commission in response to the informational filing described in Section III.13.8.1(a). Such a filing, and notification to the ISO of any such election, shall be made in accordance with the terms of Section III.13.8.1(b) and shall not limit the other rights provided under that section. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. In no case shall rejection of a de-list bid by the Internal Market Monitor restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.

(a) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

(b) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

(c) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.2(b), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor. In such a case, no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. If no such election is made, and the Existing Generating Capacity Resource is entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c), then nothing in this subsection shall restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

III.13.1.2.3.2.1.2. Net Going Forward Costs.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net going forward costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. A Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing Generating Capacity Resource's net going forward costs based on a review of the data submitted in the following formula. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{[GFC - (IMR - PER)] \times InfIndex}{(CQ_{Summer,}\ kw) \times (12, months)}$$

Where:

GFC = annual going forward costs, in dollars. These are costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

$CQ_{Summer}kW$ = capacity seeking to de-list in kW. In no case shall this value exceed the resource’s summer Qualified Capacity.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid),this value shall be calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00. As soon as practicable, the resource's total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected

InfIndex = inflation index. infIndex = $(1 + i)^4$

Where: "*i*" is the most recent reported 4- Year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.
The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.13.1.2.3.2.1.4. Risk Premium.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. This documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.13.1.2.3.2.1.2 may be included in this risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the Forward Capacity Market is consistent with the participant's corporate risk management practices.

III.13.1.2.3.2.1.5. Opportunity Costs.

To the extent that an Existing Generating Capacity Resource submitting a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, expected Capacity Performance Payments, or risk premium components of the bid, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. Administrative Export De-List Bids.

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

Age of Existing Resource (years)	Remaining Life (years)	Annual Rate of Capital Cost Recovery
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{\textit{Cost Of Capital}}{(1-(\mathbf{1}+\textit{CostOfCapital})^{-\textit{RemainingLife}})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Qualification Determination Notification for Existing Capacity.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid including a determination whether the Lead Market Participant is pivotal as described in Section III.13.1.2.3.2 and indicating whether the bid has been accepted for participation in the Forward Capacity Auction. Where a Static De-List Bid, Permanent De-List Bid, Export Bid, or Administrative Export De-List Bid is not accepted for participation in the Forward Capacity Auction as a result of the Internal Market Monitor's review pursuant to Section III.13.1.2.3.2, the notification shall include an explanation of the reasons the Existing Capacity Qualification Package was not accepted and shall include the resource's net going forward costs and opportunity costs as determined by the Internal Market Monitor. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external Demand Resource may not be an Existing Import Capacity Resource or a

New Import Capacity Resource. External nodes shall be mapped to Capacity Zones as shown in the following table:

External Node Common Name	Capacity Zone
NB-NE External Node	**Maine**
HQ Phase I/II External Node	**Rest-of-Pool**
Highgate External Node	**Rest-of-Pool**
NY-NE AC External Node	**Rest-of-Pool**
Cross Sound Cable External Node	**CT**

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control

Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. Qualified Capacity for Existing Import Capacity Resources.

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3. Qualification Process for Existing Import Capacity Resources.

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

(a) No later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting each Existing Import Capacity Resource must also submit to the ISO: (i) documentation of a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, including documentation of the MW value of the contract; or (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Existing Import Capacity Resource during the Capacity Commitment Period, together with information to establish the summer and winter ratings of the resource(s) backing the import. In either case, the Market Participant must specify the interface over which the capacity will be imported.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply. An Existing Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, Existing

Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

(c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3 for the duration of the contracts as listed. For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3, no later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3.

Contract Description	**MW**	**Contract End Date**
NYPA: NY ─ NE: CMEEC	13.2	8/31/2025
NYPA: NY ─ NE: MMWEC	53.3	8/31/2025
NYPA: NY ─ NE: Pascoag	2.3	8/31/2025
NYPA: NY─ NE: VELCO	15.3	8/31/2025
	84.1	
VJO: Highgate ─ NE	Up to 225	10/31/2016
VJO: Highgate ─ NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II ─ NE	Up to 110	10/31/2016

(d) In addition to the review described in Section III.13.1.2.3.2, the Internal Market Monitor shall review each bid from Existing Import Capacity Resources. A bid from an Existing Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.4. Definition of New Import Capacity Resource.

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

For each New Import Capacity Resource, the Market Participant submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the entire Capacity Commitment Period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New 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 (iv) documentation for system-backed import capacity that the import capacity 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. For each New Import Capacity Resource, the Market Participant must specify the interface over which the capacity will be imported. The Market Participant must indicate whether the import is associated with any investment in transmission that increases New England's import capability. If the import will be backed by a single new External Resource, the Market Participant submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the 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 New Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.

The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. 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 Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, 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 Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification 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. (3) The 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.13.1.3.5.4. Capacity Commitment Period Election.

The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall not apply. A New Import Capacity Resource may not elect to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears.

III.13.1.3.5.5. Initial Interconnection Analysis.

The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources.

For the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), the request and cost information described in Section III.13.1.1.2.2.3 and Section III.A.21.2 must be submitted to the ISO no later than November 7, 2014. In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from New Import Capacity Resources. An offer from a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity

Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5. For the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), the ISO shall, no later than December 12, 2014, send to Project Sponsors or Market Participants, as applicable, a determination regarding whether the New Import Capacity Resource is associated with a pivotal supplier as described in Section III.A.21.1.1 and the resource's New Resource Offer Floor Price as determined pursuant to Section III.A.21.2. For the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), a New Import Capacity Resource may be withdrawn (and hence not included in the Forward Capacity Auction) no later than January 16, 2015 by providing written notification of such withdrawal to the ISO. Any such withdrawal shall be irrevocable.

III.13.1.3.5.8. Rationing Election.

The rationing election described in Section III.13.1.1.2.2.3(b) shall not apply. A New Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, New Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

III.13.1.4. Demand Resources.

III.13.1.4.1. Demand Resources.

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with an early Commercial Operation Date shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2017. No resource shall be permitted to participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A

Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life. Demand 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 Resource. Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market Participant for a resource shall include the Enrolling Participant for a Demand Resource.

III.13.1.4.1.1. Existing Demand Resources.

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to ~~(i)~~ Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction~~, or (ii) Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program, as defined in Appendix E of this Market Rule 1,~~ before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.

III.13.1.4.1.2. New Demand Resources.

A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-

month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.

For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources

For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.3. Special Provisions for Real-Time Emergency Generation Resources.

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.4.2. Show of Interest Form for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor's New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. Qualification Package for Existing Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. Qualification Package for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1. [Reserved.]

III.13.1.4.2.2.2. Source of Funding.

The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3. Measurement and Verification Plan.

For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4. Customer Acquisition Plan.

A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1. Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.

For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.2.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete

III.13.1.4.2.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor's ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor's program to deliver capacity to meet the Demand Resource Project Sponsor's Forward Capacity Auction obligations, and must include each customer's projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor's ability to fulfill its obligation by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource Project Sponsor shall be subject to the ISO's critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. Capacity Commitment Period Election.

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) 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. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.2.5.

III.13.1.4.2.2.6. Rationing Election.

The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form. A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. Offers From New Demand Resources.

All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

III.13.1.4.2.5. Notification of Qualification for Demand Resources.

III.13.1.4.2.5.1. Evaluation of Demand Resource Qualification Materials.
The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

(a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;

(b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and

(e) whether the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.
For each Existing Demand Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type;

and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located, and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. Notification of Qualification for New Demand Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.

For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource's summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.

For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.3. Measurement and Verification Applicable to All Demand Resources.

To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. ~~A Net Supply Generator Asset or other Generator Asset located at the same Retail Delivery Point as a Demand Response Asset that is associated with a Demand Response Capacity Resource may not participate in the Forward Capacity Market as a Generating Capacity Resource, provided that this exclusion shall not apply to a Generator Asset if it is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.~~ 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.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects 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 Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction

Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the Demand Resource project's Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand 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. The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor's total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor's total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports 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 Demand Resource Project Sponsors. 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.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted 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 shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor's offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue 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 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors 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 Demand Resource projects targeting customer facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor 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 Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently de-listed from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.

The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation, Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, 2017, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 2017, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity Commitment Periods commencing on or after June 1, 2017, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2017, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated ~~based upon~~using the Real-Time Emeergency Generation Asset's Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the Retail Delivery Point, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated ~~based upon~~using the Real-Time Emergency Generation Asset's Average Hourly Load Reduction.

For Capacity Commitment Periods commencing before June 1, 2017, the output of the generators comprising a Real-Time Emergency Generation Asset must be directly metered and reported to the ISO as a single set of interval meter data, provided that if there is no other Real-Time Emergency Generation Asset, Real-Time Demand Response Asset or other generator whose output can be controlled at the same facility, the Market Participant may instead meter the Real-Time Emergency Generation Asset at the retail delivery point. Meter data associated with the Real-Time Emergency Generation Asset shall be recorded and reported by the Market Participant to the ISO in Real-Time at an interval of five minutes.

For Capacity Commitment Periods commencing before June 1, 2017, the output of generators comprising a Real-Time Demand Response Asset located behind the retail delivery point must be directly metered and reported to the ISO in Real-Time as a single set of interval meter data at an interval of five-minutes.

III.13.1.4.3.2.1. No Performance Data to Determine Demand Reduction Values.

Should a new Demand Resource, other than a Demand Response Capacity Resource, enter service at a time such that there is no performance data for June, July, August, December or January upon which to establish summer or winter seasonal Demand Reduction Values, and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, then the summer or winter seasonal Demand Reduction Values will be the simple average of its Demand Reduction Values for those months with a Capacity Supply Obligation. For a new Demand Resource, other than a Demand Response Capacity Resource, that enters service outside of the summer DR Auditing Period or winter DR Auditing Period and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation

Bilateral or reconfiguration auction, the Demand Resource Commercial Operation Audit results shall be used in the determination of the summer or winter seasonal Demand Reduction Value.

III.13.1.4.3.3. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor 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.13.1.4.3.4. Measurement and Verification Costs.

Costs associated with measurement and verification of the Demand Resource project shall be borne by the Demand Resource Project Sponsor. Demand Resource Project Sponsors submitting application materials and Measurement and Verification Documents for review during the Forward Capacity Auction qualification process shall be subject to the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.4.4. Dispatch of Active Demand Resources During Event Hours.

III.13.1.4.4.1. Notification of Demand Resource Forecast Peak Hours.

The ISO shall issue notice to Market Participants concerning Demand Resource Forecast Peak Hours on the day before the relevant Operating Day. The notice issued pursuant to this section is for informational purposes only and shall not constitute a Dispatch Instruction.

III.13.1.4.4.2. Dispatch of Demand Resources During Real-Time Demand Resource Dispatch Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Demand Response Resources to curtail and restore loads during Real-Time Demand Resource Dispatch Hours. Dispatch Instructions shall apply to Real-Time Demand Response Resources. The amount of Demand Resources dispatched for each Real-Time Demand Resource Dispatch Hour will be the amount that the ISO determines is necessary to meet the reserve deficiency. The ISO may issue Dispatch Instructions that reduce or increase the amount dispatched in each hour.

III.13.1.4.4.3. Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Emergency Generation Resources to curtail and restore loads during Real-Time Emergency Generation Event Hours. Dispatch Instructions shall apply to specific Real-Time Emergency Generation Resources. The amount of Real-Time Emergency Generation Resources dispatched for each Real-Time Emergency Generation Event Hour will be the amount the ISO determines is necessary to meet the reserve deficiency.

III.13.1.4.5. Selection of Active Demand Resources For Dispatch.

III.13.1.4.5.1. Management of Real-Time Demand Response Assets and Real-Time Demand Response Resources.

A Market Participant must manage its Real-Time Demand Response Assets that are registered as a component of a Real-Time Demand Response Resource as of the first of a month so that the Real-Time Demand Response Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Demand Response Assets cause, or potentially cause, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to restore the loads of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Demand Response Asset or to restore the load of a dispatched Real-Time Demand Response Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the restoration of that asset. Market Participants with Real-Time Demand Response Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Demand Response Resources consisting of an aggregation of more than one Real-Time Demand Response Asset shall report the load reduction and consumption, or generator output of the resource, to the ISO as the sum of the load reduction, consumption, or generator output of the individual assets making up that resource. Real-Time Demand Response Resources shall be assigned a unique resource identification number. The load reduction and consumption, or generator output of a Real-Time Demand Response Resource is reported to the ISO as a single set of values. A Real-Time Demand Response Resource shall consist of one or more Real-Time Demand Response Assets that are located within the same Dispatch Zone.

III.13.1.4.5.2. Management of Real-Time Emergency Generation Assets and Real-Time Emergency Generation Resources.

A Market Participant must manage its Real-Time Emergency Generation Assets that are registered as a component of a Real-Time Emergency Generation Resource as of the first of a month so that the Real-Time Emergency Generation Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Emergency Generation Assets causes, or potentially causes, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to discontinue the output of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Emergency Generation Asset or to discontinue the output of a dispatched Real-Time Emergency Generation Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the discontinued output of that asset. Market Participants with Real-Time Emergency Generation Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Emergency Generation Resources consisting of an aggregation of more than one Real-Time Emergency Generation Asset shall report the generator output of the resource to the ISO as the sum of the generator outputs of the individual assets making up that resource. Real-Time Emergency Generation Resources shall be assigned a unique resource identification number. The generator output of a Real-Time Emergency Generation Resource is reported to the ISO as a single set of values. A Real-Time Emergency Generation Resource shall consist of one or more Real-Time Emergency Generation Assets that are located within the same Dispatch Zone.

III.13.1.4.5.3. [Reserved.]

III.13.1.4.6. Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at Dispatch Zones.

III.13.1.4.6.1. Establishment of Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location and dispatch of Demand Response Capacity Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources. Dispatch Zones shall not change during a Capacity Commitment Period. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission

Window of the applicable Forward Capacity Auction. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.13.1.4.6.2. Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

III.13.1.4.6.2.1. Real-Time Demand Response Resource Disaggregation.
Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Demand Response Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Demand Response Resource into one or more Real-Time Demand Response Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.6.2.2. Real-Time Emergency Generation Resource Disaggregation.
Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Emergency Generation Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Emergency Generation Resource into one or more Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch

Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.7. [Reserved.]

III.13.1.4.8. [Reserved.]

III.13.1.4.9. Restrictions on Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Registration.

A Market Participant may not register and, if previously registered, must retire in accordance with Section III.13.1.4.9.1, a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

III.13.1.4.9.1. Requirement for Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Retirement.

A Market Participant must retire a previously registered Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak

Demand Resource that is comprised of customers specified in subsections (a) or (b) of Section III.13.1.4.9 no later than 12 months from the date that the ISO receives notice that the relevant electric retail regulatory authority prohibits such customer's demand response to be bid into the ISO-administered markets or programs or May 31, 2013, whichever is later.

III.13.1.4.10. Providing Information On Demand Response Capacity, Real-Time Demand Response and Real-Time Emergency Generation Resources.

If requested by a Market Participant with a registered Load Asset, the ISO will provide the following information about end-use customers served by the Market Participant: (a) whether the end-use customer's facility is registered with the ISO as part of an asset and whether the asset is associated with a Demand Response Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource, and; (b) the load reduction capability of the asset, as specified in the ISO's asset registration system, to which the end-use customer's facility is registered.

III.13.1.4.11. Assignment of Demand Assets to a Demand Resource.

The following mapping provisions apply to Demand Resources other than Demand Response Capacity Resources, the mapping for which is addressed in Appendix E to Market Rule 1.

(a) When a demand asset can be mapped to more than one Demand Resource, any demand assets shall be mapped to a commercial Demand Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period, before being mapped to a non-commercial Demand Resource or non-commercial increment of a Demand Resource.

(b) A demand asset cannot be unmapped from a Demand Resource if, following the unmapping, the sum of the audit values of the remaining demand assets that are mapped to the Demand Resource would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.2.4.5.3. Offers composed of separate resources may not be modified or withdrawn after the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Resource, April through November where the summer resource is a Demand Resource) 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 (October through May where the summer resource is not a Demand Resource, December through March where the summer resource is a Demand Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered 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 an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources 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.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource or Intermittent Settlement Only Resource. If the winter capacity of the offer composed of separate resources 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) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone.

(e) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained.

(f) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone.

(g) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource.

(h) A Renewable Technology Resource may only participate in an offer composed of separate resources if its FCA Qualified Capacity has not been prorated pursuant to Section III.13.1.1.2.10.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than 5 Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource's final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource's financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the financial assurance deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c) and, with the exception of demand programs for Self-Supplied FCA 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 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.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources 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 FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

(a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) If a Permanent De-List Bid above the Dynamic De-List Bid Threshold or a Static De-List Bid is approved by the Internal Market Monitor, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.13.1.9. Financial Assurance.

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy. The ISO and the NEPOOL Budget and Finance Subcommittee shall reconsider these financial assurance requirements no later than five years after the first Forward Capacity Auction is conducted.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Generating Capacity Resources) and New Demand Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the financial assurance deposit specified in the ISO New England Financial Assurance Policy by the Project Sponsor for a New Generating Capacity Resource or New Demand Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Resource in the Forward Capacity Auction at the starting price. If this financial assurance deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit shall be applied toward the resource's financial assurance obligation, as described in the ISO New England Financial Assurance

Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit will be returned pursuant to the terms of the ISO New England Financial Assurance Policy.

III.13.1.9.2. Financial Assurance for New Generating Capacity Resources and New Demand Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Resource's offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Resource: (i) fails to provide the required financial assurance on any required date for any reason; or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4(c), it shall lose its Capacity Supply Obligation (which shall then be entered by the ISO into subsequent annual reconfiguration auctions) and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. Release of Financial Assurance.

Once a New Generating Capacity Resource or New Demand Resource achieves Commercial Operation and is tested for its capacity rating, 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 an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand 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 resulting shortfall in capacity shall then be entered by the ISO into subsequent annual reconfiguration auctions.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. Forfeit of Financial Assurance.

Where any financial assurance is forfeited pursuant to the provisions of this Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to the provisions of this Section III.13 shall be used to reduce payments incurred by load in the relevant Capacity Zone to replace that capacity.

III.13.1.9.2.4. Financial Assurance for New Import Capacity Resources.

A New Import Capacity Resource that is backed by a new External Resource shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource achieves Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. Qualification Process Cost Reimbursement Deposit.

For each New Capacity Show of Interest Form and New Demand Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below ("Qualification Process Cost Reimbursement Deposit"). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project's critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual 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. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22 or 23 of the OATT or where a resource modification does not require a revision to the Interconnection Agreement.

New Generating Resources ≥ 20 MW	**New Generating Resources < 20 MW and ≥ 2 MW**	**Imports and New Demand Resources (including Distributed Generation)**		**New Generating Resources < 2 MW**
Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources	*Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources*			
$25,000	$7,500	$1,000		$500
With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement	*With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement*			
$15,000	$6500	n/a		n/a

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for Commercial Operation, the ISO shall provide the Project Sponsor 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. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds 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, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If 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 exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO's consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
For all resources except Demand Resources, Nov. 1, 2006 through Jan. 2, 2007 For Demand Resources, Dec. 18, 2006 through Feb. 28, 2007	Apr. 30, 2007	June 15, 2007	Feb. 4, 2008	June 1, 2010
Sept. 18, 2007 through Nov. 14, 2007	Mar. 14, 2008	Apr. 29, 2008	Dec. 8, 2008	June 1, 2011
July 15, 2008 through Sep. 16, 2008	Feb. 3, 2009	Feb. 17, 2009	Oct. 5, 2009	June 1, 2012
May 15, 2009 through July 14, 2009	Dec. 1, 2009	Dec. 15, 2009	Aug. 2, 2010	June 1, 2013
Mar. 15, 2010 through May 14, 2010	Oct. 1, 2010	Oct. 15, 2010	June 6, 2011	June 1, 2014
Mar. 1, 2011 through Mar. 14, 2011	Aug. 1, 2011	Aug. 15, 2011	Apr. 2, 2012	June 1, 2015
Jan. 3, 2012 through Jan. 17, 2012	June 1, 2012	June 15, 2012	Feb. 4, 2013	June 1, 2016
Feb. 14, 2013 through Feb. 28, 2013	June 3, 2013	June 17, 2013	Feb. 3, 2014	June 1, 2017

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

(a) each Capacity Commitment Period shall begin in June;

(b) the New Capacity Show of Interest Submission Window will be in February (after the Forward Capacity Auction for the prior Capacity Commitment Period), approximately four years and three months before the beginning of the Capacity Commitment Period;

(c) the Existing Capacity Qualification Deadline will be in June just over four years before the beginning of the Capacity Commitment Period;

(d) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and

(e) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

The table below shows this generic timeline for the Capacity Commitment Period beginning in year "X", where X is any year after 2015.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
Feb. (X-4)	June (X-4)	June/July (X-4)	Feb. (X-3)	June X

III.13.1.11 Opt-Out for Resources Electing Multiple-Year Treatment.

Beginning in the qualification process for the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), any resource that had elected in a Forward Capacity

Auction prior to the ninth Forward Capacity Auction (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer cleared may, by submitting a written notification to the ISO no later than the Existing Capacity Qualification Deadline (or, in the case of the ninth Forward Capacity Auction, no later than September 19, 2014), opt-out of the remaining years of the resource's multiple-year election. A decision to so opt-out shall be irrevocable. A resource choosing to so opt-out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.

III.13.5. Bilateral Contracts in the Forward Capacity Market.

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals and Supplemental Availability 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.

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 monthly Capacity Supply Obligation Bilateral must be coterminous with a calendar month, and an annual Capacity Supply Obligation Bilateral must be coterminous with a Capacity Commitment Period.

(b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly Capacity Supply Obligation of the Capacity Transferring Resource during the period covered by the Capacity Supply Obligation Bilateral. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly 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 for the relevant time period) of the Capacity Acquiring Resource during the period 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) A Real-Time Emergency Generation Resource may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource.

(e) [Reserved.]

(f) [Reserved.]

(g) Prior to April 1, 2015, if the Capacity Acquiring Resource is an Import Capacity Resource, then the Capacity Transferring Resource must also be an Import Capacity Resource on the same external interface.

(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 Capacity Commitment Period month.

(j) A resource that has not achieved Commercial Operation by the submission deadline for a monthly Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that Capacity Commitment Period 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.

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 before or during submittal windows, as defined in the ISO New England Manuals and ISO New England Operating

Procedures. The ISO will issue a schedule of the submittal windows for annual and monthly 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 generation or Demand Response Resource outage information, and will include transmission security studies. The ISO will review all confirmed monthly Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. For a monthly Capacity Supply Obligation Bilateral, 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 review the net impact of all annual Capacity Supply Obligation Bilaterals to ensure that the regional and local adequacy and other reliability needs achieved through the Forward Capacity Auction are maintained in the Capacity Transferring Resource's Capacity Zone and the Capacity Acquiring Resource's Capacity Zone or across the external interface.

If after its review of the net impact of all annual Capacity Supply Obligation Bilaterals the ISO determines that the regional and local adequacy and other reliability needs achieved through the Forward Capacity Auction are not maintained, and for all monthly Capacity Supply Obligation Bilaterals, the 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 settlement 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 second Business Day after the end 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. Supplemental Availability Bilaterals.

A resource's availability score during a Shortage Event may be supplemented by entering into a Supplemental Availability Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. Designation of Supplemental Capacity Resources.

III.13.5.3.1.1. Eligibility.

Demand Response Capacity Resources and Generating Capacity Resources that are not Intermittent Power Resources or Settlement Only Resources may be designated as Supplemental Capacity Resources. A Generating Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource's CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales submitted in accordance with Section III.1.10.7(f) from that resource and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource. A Demand Response Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource's Qualified Capacity from the Forward Capacity Auction for the current Capacity Commitment

Period pursuant to Section III.13.1.4.1 and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource.

III.13.5.3.1.2. Designation.

The designation of a Supplemental Capacity Resource must be made by the resource's Lead Market Participant. The designation shall indicate the term for which the resource is designated as a Supplemental Capacity Resource, which shall be in Operating Day increments, no less than one Operating Day, and no greater than one calendar month. Such designation shall indicate the MW amount being designated as a Supplemental Capacity Resource, and the Capacity Zone in which the resource is located. Such designation must be submitted to the ISO no later than the deadline for the submission of Supply Offers in the Day-Ahead Energy Market for the first Operating Day of the indicated term.

III.13.5.3.1.3. ISO Review.

The ISO shall review the information provided in submission of the designation as a Supplemental Capacity Resource, and shall reject the designation for any of the hours in which any of the provisions of this Section III.13.5.3.1 are not met.

III.13.5.3.1.4. Effect of Designation.

Regardless of whether it ever becomes subject to a Supplemental Availability Bilateral as described in Section III.13.5.3.2, the portion of a resource designated as a Supplemental Capacity Resource is subject to the same energy market offer requirements applicable to a resource having a Capacity Supply Obligation as described in Sections III.13.6.1.1.1 and III.13.6.1.1.2 for Generating Capacity Resources and as described in Sections III.13.6.1.5.1. and III.13.6.1.5.2. for Demand Response Capacity Resources for the entire term indicated in the designation described in Section III.13.5.3.1.2.

III.13.5.3.2. Submission of Supplemental Availability Bilaterals.

The Lead Market Participant for a resource previously designated as a Supplemental Capacity Resource in accordance with the provisions of Section III.13.5.3.1 for a term that included a Shortage Event may submit a Supplemental Availability Bilateral to the ISO assigning all or a portion of its available capability up to its designated supplemental capacity in each hour of that Shortage Event to a Generating Capacity Resource or Demand Response Capacity Resource having a Capacity Supply Obligation during that Shortage Event ("Supplemented Capacity Resource"). No other Market Participant may submit a Supplemental Availability Bilateral. The Supplemental Capacity Resource and the Supplemented Capacity Resource must either: (i) be located in the same Reserve Zone (although in no case may a

Supplemental Capacity Resource located in an export-constrained Capacity Zone provide supplemental availability outside of that export-constrained Capacity Zone); or (ii) be located in different Reserve Zones such that direction of flow between the Supplemental Capacity Resource and the Supplemented Capacity Resource is counter to any Reserve Zone or Capacity Zone constraint. For purposes of this Section III.13.5.3.2, a Reserve Zone having a locational reserve requirement (established pursuant to Section III.9.2.2) that is less than or equal to zero shall be considered to be unconstrained with respect to the neighboring Reserve Zone. A Supplemental Capacity Resource may submit Supplemental Availability Bilaterals with multiple Supplemented Capacity Resources, but each MW of supplemental capacity may only be assigned to one Supplemented Capacity Resource. No Supplemental Capacity Resource may itself be a Supplemented Capacity Resource for an hour.

III.13.5.3.2.1. Timing.

A Supplemental Availability 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 Supplemental Availability Bilateral, a Supplemental Availability 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 Supplemental Availability Bilateral may be revised by the parties to the transaction throughout the resettlement process). A Supplemental Availability Bilateral must be confirmed by the Lead Market Participant for the Supplemented Capacity Resource no later than the same deadline that applies to submission of the Supplemental Availability Bilateral.

III.13.5.3.2.2. Application.

The submission of a Supplemental Availability Bilateral to the ISO shall include the following: (i) the resource identification number for the Supplemental Capacity Resource; (ii) the resource identification number for the Supplemented Capacity Resource; (iii) the MW amount of capacity being assigned from the Supplemental Capacity Resource to the Supplemented Capacity Resource; (iv) the term of the transaction, which shall be in hourly increments coinciding with hourly boundaries, no less than one hour, and no greater than one calendar month.

III.13.5.3.2.3. ISO Review.

The ISO shall review the information provided in submission of the Supplemental Availability Bilateral, and shall reject the Supplemental Availability Bilateral if any of the provisions of this Section III.13.5.3 are not met. The ISO shall reject the applicability of a Supplemental Availability Bilateral in any hour of a Shortage Event unless: (i) the Supplemental Capacity Resource was on-line and following ISO dispatch instructions during that hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is (a) less than or equal to the difference between the Generating Capacity Resource's Economic Maximum Limit as submitted or redeclared by the Lead Market Participant and the Supplemental Capacity Resource's Capacity Supply Obligation or (b) less than or equal to the difference between (the greater of the sum of the Real-Time Demand Reduction Obligations of the Demand Response Resources associated with the Demand Response Capacity Resource~~'s Real-Time Demand Reduction Obligation~~ or the lesser of ((the sum of the Demand Response Baselines of the Demand Response Assets comprising the Demand Response Resources associated with the Demand Response Capacity Resource~~'s Demand Response Baseline~~ as adjusted pursuant to Section III.8B.5, plus ~~the Economic Maximum Limit for any associated available Net Supply Generator Assets~~the Net Supply Limit of the Demand Response Resources), the Hourly Adjusted Audited Demand Reduction, or (the Maximum Reduction as submitted or redeclared by the Lead Market Participant plus the ~~Economic Maximum Limit of associated Net Supply Generator Assets~~Net Supply Limit of the Demand Response Resources))), adjusted for average avoided peak transmission and distribution losses as addressed in Section III.13.7.1.5.10, and the Supplemental Capacity Resource's Capacity Supply Obligation; or (ii) the Supplemental Capacity Resource was offline for the hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is less than or equal to the difference between the sum of the Supplemental Capacity Resource's Real-Time Reserve Designations of TMNSR, TMSR and TMOR and the Supplemental Capacity Resource's Capacity Supply Obligation.

III.13.5.3.2.4. Effect of Supplemental Availability Bilateral.

A Supplemental Availability 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 Supplemental Availability Bilateral is to modify the Supplemented Capacity Resource's availability score as described in Section III.13.7.1.1.4.

III.13.6. Rights and Obligations.

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. Generating Capacity Resources.

III.13.6.1.1.1. Energy Market Offer Requirements.

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:

(a) 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

(b) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a) 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.

III.13.6.1.1.2. 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 economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.1.3. [Reserved.]

III.13.6.1.1.4. [Reserved.]

III.13.6.1.1.5. 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;

(c) 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 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.13.6.1.2. Import Capacity Resources.

III.13.6.1.2.1. Energy Market Offer Requirements.

A Market Participant must offer energy associated with an Import Capacity Resource with a Capacity Supply Obligation into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions for every hour of each Operating Day at the same external interface totaling an amount (MW) equal to the Capacity Supply Obligation unless the Import Capacity Resource is associated with an External Resource that is on an outage. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with this requirement may be subject to sanctions pursuant to Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.2 for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.

The offer requirements of Section III.13.6.1.2.1 will not apply to External Transactions associated with the VJO and NYPA Import Capacity Resources specified in Section III.13.1.3.3(c) for the duration of the contract provided the transactions are self-scheduled in both the Day-Ahead Energy Market and Real-Time Energy Market. If the energy associated with these contracts is not self-scheduled, the offer requirements and provisions of this section will apply to the applicable contract.

(a) All priced External Transactions associated with an Import Capacity Resource with a Capacity Supply Obligation must be offered each hour at or below the greater of either: (1) the offer threshold specified in Section III.13.6.1.2.1(b) for the Operating Day; (2) the offer threshold determined for the prior Operating Day; and (3) for any priced External Transactions from the New York Control Area the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface.

(b) A daily offer threshold will be determined for each Operating Day and will apply to each hour of the Operating Day. From June 1, 2010 to May 31, 2013 the daily offer threshold is equal to the product of the PER Proxy Unit heat rate as described in Section III.13.7.2.7.1.1.1(b)(iii) and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation of day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis. After May 31, 2013 the daily offer threshold is equal to the product of the applicable Forward Reserve Heat Rate as described in Section III.9.6.2 and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.

(c) Submittal of External Transactions to the Day-Ahead Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource requires submittal of matching energy transactions to the Real-Time Energy Market; the External Transactions submitted to the Real-Time Energy Market must match the External Transactions submitted to the Day-Ahead Energy Market, subject to the right to submit different prices into the Real-Time Energy Market.

(d) External Transactions submitted to the Real-Time Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource must be submitted prior to the offer submission deadline for the Day-Ahead Energy Market the day before the Operating Day for which they are intended to be scheduled.

(e) A Market Participant submitting a priced External Transaction supporting an Import Capacity Resource with a Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must link the transaction to the associated transmission reservation and NERC E-Tag no later than one hour before the operating hour in order to be eligible for scheduling in the Real-Time Energy Market. If a Market Participant does not link the transaction to the associated transmission reservation and NERC E-Tag in the Real-Time Energy Market for any hour during which the External Transaction would otherwise have been economically and reliably scheduled in the Real-Time Energy Market, the associated Import Capacity Resource shall be treated as having not delivered energy for the hour despite ISO requested dispatch under Section III.13.7.1.2 and III.13.7.2.7.2. A Market Participant submitting any other External Transaction to the Real-Time Energy Market must comply with the requirements in Section III.1.10.7(e) with respect to linking the transaction to the associated transmission reservation and NERC E-Tag.

III.13.6.1.2.2. Additional Requirements for Import Capacity Resources.

Import Capacity Resources are subject to the following additional requirements:

(a) information submittal requirements for External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals;

(b) resource backed Import Capacity Resources shall be subject to the outage requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures. Control Area backed Import Capacity Resources are not subject to such outage requirements;

(c) resource backed Import Capacity Resources are subject to the voluntary and mandatory re-scheduling of maintenance procedures outlined in the ISO New England Operating Procedures and ISO New England Manuals.

(d) at the time of submittal, each External Transaction shall reference the associated Import Capacity Resource.

III.13.6.1.3. Intermittent Power Resources.

III.13.6.1.3.1. Energy Market Offer Requirements.
Intermittent Power Resources may submit offers into the Day-Ahead Energy Market. Such resources are required to submit offers 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.

III.13.6.1.3.2. [Reserved.]

III.13.6.1.3.3. Additional Requirements for Intermittent Power Resources.
Intermittent Power Resources 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;

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.1.4.1. Energy Market Offer Requirements.
Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.4.2. Additional Requirements for Settlement Only Resources.
Intermittent Settlement Only Resources and Non-Intermittent Settlement Only 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;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.5. Demand Resources.

III.13.6.1.5.1. Energy Market Offer Requirements.

Seasonal Peak Demand Resources, On-Peak Demand Resources and Real-Time Emergency Generation Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Markets. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E.

Commencing June 1, 2017, a Market Participant with~~A~~ a Demand Response Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers ~~through~~ for its Demand Response Resources ~~and submit Supply Offers of any associated Net Supply Generator Assets,~~ into ~~both~~ the Day-Ahead Energy Market and Real-Time Energy Market. ~~through its Demand Response Resources and associated Net Supply Generator Assets.~~ The sum of the Demand Reduction Offers ~~and Supply Offers~~ must be equal to or greater than the Demand Response Capacity Resource's Capacity Supply Obligation whenever the Demand Response Resources ~~and associated Net Supply Generator Assets~~ are physically available. ~~If the Net Supply Generator Asset is a Settlement Only Resource, then the Net Supply will not be represented in the offer for the Demand Response Resource.~~ If the Demand Response Resources ~~and~~

~~associated Net Supply Generator Assets~~ are physically available at a level less than the Demand Response Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers ~~and Supply Offers~~ will equal ~~to~~ 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 one of the following requirements:

(a) 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) the sum of the Demand Response Resource's Minimum Reduction Time plus the Minimum Time Between Reductions is less than or equal to 24 hours.

~~Each Supply Offer for a Net Supply Generator Asset associated with a Demand Response Resource made into the Day-Ahead Energy Market shall also meet one of the following requirements:~~

~~(a) the sum of the Net Supply Generator Asset's Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours.~~

~~(b) the sum of the Net Supply Generator Asset's Minimum Run Time plus Minimum Down Time is less than or equal to 24 hours.~~

III.13.6.1.5.2. Requirement that Offers Reflect Accurate Demand Response Capacity Resource Operating Characteristics.

For each day, Demand Reduction Offers ~~and, if applicable, Supply Offers of associated Net Supply Generator Assets,~~ submitted into the Day-Ahead Energy Market and Real-Time Energy Market for ~~the portion of~~ a resource Demand Response Resources associated with a Demand Response Capacity Resource ~~having a Capacity Supply Obligation~~ must reflect the then-known operating characteristics of the resource. Resources must re-declare to the ISO any changes to the 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 economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.5.3. Additional Requirements for Demand Resources.

Demand Resources shall comply with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals and the auditing and rating requirements as detailed in Section III.13.6.1.5.4 and the ISO New England Manuals. Demand Response Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1;

(b) 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 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.13.6.1.5.4. Demand Response Auditing.

Demand Resources shall be subject to ISO conducted audits for the purposes of:

(a) Auditing Demand Reduction Values or determining the Audited Demand Reduction for a Demand Resource;

(b) Verifying the Commercial Operation of a Demand Resource; and

(c) Verifying the Demand Reduction Value or the Audited Demand Reduction of the Demand Resource when the ISO, based on objective criteria, has determined that the Demand Reduction Value or the Audited Demand Reduction of a Demand Resource may not be credible.

New Demand Response Asset Audits shall be performed pursuant to Section III.13.6.1.5.4.8.

III.13.6.1.5.4.1. General Auditing Requirements for Demand Resources Excluding Demand Response Capacity Resources.

(a) Audits of a Demand Resource will be conducted by simultaneously evaluating the performance of each demand asset that is mapped to that Demand Resource.

(b) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Real-Time Demand Response Resources containing Real-Time Demand Response Assets that are located behind the same end-use customer meter as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource.

(c) An audit is valid beginning with the month in which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like seasonal DR Auditing Period. Additional audits performed in a month shall not replace the results of the initial audit conducted in a month and are valid on the first of the subsequent month following the audit. Audit results shall not replace a Demand Reduction Value that is based on Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours.

(d) If one or more demand assets of a Demand Resource do not have audit results at the time the Demand Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those demand assets toward the audit value of the Demand Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit provided the demand asset was available for dispatch by the ISO in that prior month, and if the demand asset was not available for dispatch in that prior month, then the 1st of the month in which the demand asset was available for dispatch.

III.13.6.1.5.4.2. General Auditing Requirements for Demand Response Capacity Resources.

(a) Audits of Demand Response Resources associated with a Demand Response Capacity Resource will be conducted by simultaneously evaluating the performance of each Demand Response Asset ~~and Net Supply Generator Asset~~ that is mapped to ~~each associated~~a Demand Response Resource. The Demand Response Resources associated with a Demand Response Capacity Resource are not required to be evaluated simultaneously.

(b) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Demand Response Resources containing Demand Response Assets that are located behind the same Retail Delivery Point as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource. When the output of the Real-Time

Emergency Generation Asset is greater than the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of the Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Net Supply is reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset.

(c) An audit is valid beginning with the date on which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like Seasonal DR Audit period. For the Capacity Commitment Period commencing on June 1, 2017, the audit results for Demand Response Resources comprised of Demand Response Assets ~~and associated Net Supply Generator Assets~~ that were associated with a Real-Time Demand Response Resource in the prior Capacity Commitment Period shall be the sum of the audit results for those assets in the prior like Seasonal DR Audit period. When using audit results from a period prior to June 1, 2017 for those former Real-Time Demand Response Assets, the Audited Full Reduction Time shall be 30 minutes.

(d) If one or more Demand Response Assets of a Demand Response Resource ~~or associated Net Supply Generator Assets~~ do not have an Audited Demand Reduction at the time the Demand Response Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those Demand Response Assets ~~or associated Net Supply Generator Assets~~ toward the Audited Demand Reduction of the Demand Response Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit, provided the Demand Response Asset ~~or associated Net Supply Generator Asset~~ was available for dispatch by the ISO in that prior month, and if the Demand Response Asset ~~or associated Net Supply Generator Asset~~ was not available for dispatch in that prior month, then the 1st of the month in which the Demand Response Asset ~~or associated Net Supply Generator Asset~~ was available for dispatch.

III.13.6.1.5.4.3. Seasonal DR Audits.

A Seasonal DR Audit must be conducted for each Demand Resource during each seasonal DR Auditing Period.

III.13.6.1.5.4.3.1. Seasonal DR Audit Requirement.

A Market Participant shall submit each Demand Resource to an ISO initiated audit each season to verify the Demand Reduction Value or Audited Demand Reduction for the resource for one or more months of the season. The Seasonal DR Audit must be requested by the Market Participant for the Demand Resource within each Capacity Commitment Period in which the Demand Resource has a Capacity Supply Obligation. The summer DR Auditing Period begins on June 1 and ends on August 31. The winter DR Auditing Period begins on December 1 and ends on January 31. For all Demand Resources other than Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the audit results for the months of June, July, and August, and audits performed during the winter DR Auditing Period will be used to establish the audit results for the months of December and January. For Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource summer months of June, July, August, September, October, November, and the following April and May, and audits performed during the winter DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource winter months of December and the following January, February and March.

III.13.6.1.5.4.3.2. Failure to Request or Perform an Audit.

If by the 1st of August for the summer DR Auditing Period or by the 1st of January for the winter DR Auditing Period a Market Participant has not requested a Seasonal DR Audit for a Demand Resource, the Market Participant shall be deemed to have requested a Seasonal DR Audit on those respective dates. A Demand Resource that does not successfully perform a Seasonal DR Audit for a DR Auditing Period shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

III.13.6.1.5.4.3.3. Use of Event Performance Data to Satisfy Audit Requirements for Certain Resources.

A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource that has received a Dispatch Instruction in a season for 100% of its highest CSO for the current DR Auditing Period lasting at least one hour, not including the 30 minute Demand Response Resource Notification Time, may use the first 60 minute period of the event after the 30 minute Demand Response Resource Notification Time to satisfy the Seasonal DR Audit requirement for the applicable DR Auditing Period, subject to the provisions of Section III.13.6.1.5.4.1(b). A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource's audit value under this provision is based on the average load reduction or output demonstrated over the duration of the qualifying 60 minute period.

A Market Participant must request that an event be used to satisfy the Demand Resource's Seasonal DR Audit requirement or replace a currently effective audit result within seven days of the Operating Day on which the Dispatch Instruction for the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is received.

III.13.6.1.5.4.3.3.1. Demand Response Capacity Resources.

A Demand Response Capacity Resource may elect to use performance associated with a Shortage Event as defined in Section III.13.7.1.1.1 or a time period when the ISO has declared a capacity deficiency pursuant to ISO New England Operating Procedure No. 4 that occurs during a DR Auditing Period in place of requesting a Seasonal DR Audit; provided that any Demand Response Asset of a Demand Response Resource associated with the Demand Response Capacity Resource on a forced curtailment or scheduled curtailment as defined in Section III.13.7.1.5.10.2 is assessed a zero audit value.

If a Demand Response Resource associated with a Demand Response Capacity Resource does not reduce demand for some portion of the event, the audit results of its Demand Response Assets ~~and associated Net Supply Generator Assets~~ shall be set to zero. Otherwise, the Demand Response Resources associated with a Demand Response Capacity Resource will be measured based upon their offered parameters per Section III.13.6.1.5.4.6(d), and the Audited Demand Reduction for each Demand Response Resource will be capped at the average Desired Dispatch Point ~~(~~for the Demand Response Resource ~~and its associated Net Supply Generator Assets)~~ over the audit duration by proportionally reducing each associated Demand Response Asset's ~~and Net Supply Generator Asset's~~ audit results.

Within 7 calendar days of the event, the participant must inform the ISO that it wishes to use dispatch performance during the event to establish the ~~resource's~~ Demand Response Resource's Audited Demand Reduction.

If a Shortage Event occurs before a Demand Response Resource has established an Audited Demand Reduction value and the resource was not dispatched during the Shortage Event at a level equal to its Maximum Reduction, a Market Participant may elect within seven calendar days after the event to set the Audited Demand Reduction of the Demand Response Resource equal to its CLAIM10 or CLAIM30 value at the time of the event as determined pursuant to Section III.9.5.3.

A Market Participant may elect to use performance associated with a CLAIM10 or CLAIM30 audit of a Demand Response Resource that occurs during a DR Auditing Period in place of requesting a Seasonal

DR Audit of that resource provided that the audit was conducted in a manner that meets the requirements of a Seasonal DR Audit. Within seven calendar days of the CLAIM10 or CLAIM30 audit, the Market Participant must inform the ISO that it wishes to use dispatch performance during the audit to establish the Demand Response Resource's Seasonal DR Audit value.

III.13.6.1.5.4.4. Demand Resource Commercial Operation Audit.

(a) A Market Participant with a Demand Resource that has one or more increments that have not demonstrated commercial operation prior to the commencement of a Capacity Commitment Period shall perform a Demand Resource Commercial Operation Audit. The results of the Demand Resource Commercial Operation Audit shall be used to verify the commercial capacity of the Demand Resource and establish the Audited Demand Reduction of a Demand Response Resource.

(b) If a Demand Resource Commercial Operation Audit is not performed prior to the commencement of the Capacity Commitment Period, an audit must be requested in time for performance within the first month in which the Demand Resource has a Capacity Supply Obligation in the Capacity Commitment Period or the Commercial Operation Date, whichever is earlier. A Demand Resource that does not successfully perform a Demand Resource Commercial Operation Audit prior to the end of the first month in which the Demand Resource has a Capacity Supply Obligation shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

(c) A Demand Resource that fails to demonstrate through its Demand Resource Commercial Operation Audit a demand reduction in the amount of its Capacity Supply Obligation shall be subject to the provisions of Section III.13.1.9 and Section III.13.3.4.

(d) A Market Participant may request additional Demand Resource Commercial Operation Audits during a Capacity Commitment Period to verify an increase in the commercial capacity of a Demand Resource.

(e) If a Demand Resource has summer Qualified Capacity, a Demand Resource Commercial Operation Audit must be performed during the summer season (April through November) to verify the commercial capacity of the resource. A Demand Resource Commercial Operation Audit performed during the winter season (December through March) may only be used to verify the winter commercial capacity of the resource.

(f) A Demand Resource Commercial Operation Audit performed during a summer DR Auditing Period or winter DR Auditing Period may be used to satisfy the Seasonal DR Audit requirement for the same seasonal period. If a Demand Resource conducts a Demand Resource Commercial Operation Audit outside of a summer DR Auditing Period or winter DR Auditing Period, the Seasonal DR Audit requirement shall not be satisfied, however the results shall be used in the calculation of the summer Seasonal DR Audit value or winter Seasonal DR Audit value as follows:

(1) A Demand Resource Commercial Operation Audit conducted in the months of September, October, November, April, or May shall be considered a summer Seasonal DR Audit;

(2) A Demand Resource Commercial Operation Audit conducted in February or March shall be considered a winter Seasonal DR Audit.

III.13.6.1.5.4.5. Additional Audits.

The ISO may initiate an audit to verify the Demand Reduction Value or Audited Demand Reduction of a Demand Resource when an evaluation based on objective criteria indicates a Market Participant is claiming demand reductions in excess of the Demand Resource's actual capability. Such criteria include, but are not limited to:

(a) A pattern of submitting to the ISO a level of available interruption that is less than the resource's Demand Reduction Value or Audited Demand Reduction during the same time period;

(b) Actual loads for the underlying assets of the resource that, when aggregated, are below the resource's Demand Reduction Value or Audited Demand Reduction; or

(c) Failure to achieve the dispatched interruption.

The results of an additional audit shall replace the results of the last like Seasonal DR Audit or Demand Resource Commercial Operation Audit.

The ISO may perform additional audits for a Demand Resource to establish the audit results or Audited Demand Reduction and the performance of the installed measures of the demand asset or Demand

Response Asset~~ and associated Net Supply Generator Asset~~. This additional auditing may consist of two levels.

(a) Level 1 Audit: the ISO will establish the audit results by conducting a review of records of the demand asset or Demand Response Asset ~~and associated Net Supply Generator Asset~~ to verify that the reported 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 measures in the demand asset or Demand Response Asset~~ and associated Net Supply Generator Asset~~. 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 Resource is less than or greater than its Demand Reduction Value or Audited Demand Reduction in the same period, then the Demand Reduction Value or Audited Demand Reduction shall be adjusted to the value demonstrated through the audit.

III.13.6.1.5.4.6. Audit Methodologies.

(a) For On-Peak Demand Resources, audit results shall be established based on the Average Hourly Output or Average Hourly Load Reduction in the DR Auditing Period.

(b) For Seasonal Peak Demand Resources, audit results shall be established based on Average Hourly Output or Average Hourly Load Reduction or their equivalent in the DR Auditing Period.

(c) For Real-Time Demand Response Resources and Real-Time Emergency Generation Resources, audits will be conducted via a Dispatch Instruction sent by the ISO. Audit results for a Real-Time Demand Response Resource and Real-Time Emergency Generation Resource will be based on the sum of the average load reductions or average incremental output demonstrated during the audit by each demand asset mapped to the Demand Resource.

(d) For Demand Response Resources associated with Demand Response Capacity Resources, audits will be conducted via a Dispatch Instruction~~ sent by the ISO~~. Audit results for ~~a ~~the Demand Response ~~Capacity ~~Resources will be based on the sum of the average ~~load ~~demand reductions ~~or average Net Supply ~~demonstrated during the audit by each Demand Response Asset ~~and associated Net Supply Generator Asset ~~associated with the Demand Response Resource that is mapped to the Demand Response Capacity Resource using (i) each Demand Response Resource's Offered Full Reduction Time to establish the start of the audit period and (ii) the Minimum Reduction Time adjusted for ramping time as the audit duration. The Offered Full Reduction Time is the Demand Response Resource Notification Time plus the Demand Response Resource Start-Up Time plus ((the Maximum Reduction ~~plus the sum of the Economic Maximum Limits of any associated available Net Supply Generator Assets ~~minus the Minimum Reduction) divided by the Demand Response Resource Ramp Rate). For purposes of determining the Offered Full Reduction Time, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the ~~Economic Maximum Limit of the Net Supply Generator Asset~~Maximum Reduction is reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset.

III.13.6.1.5.4.7. Requesting and Performing an Audit.

(a) Seasonal DR Audits and Demand Resource Commercial Operation Audits will be performed following the request of the Market Participant. Audits will be performed within 20 Business Days of the date requested by the Market Participant. The date and time of the audit will be unannounced. An audit request may be denied by the ISO, and an audit may be rescheduled, if its performance will jeopardize the reliable operation of the electrical system.

(b) Seasonal DR Audits may be performed on different dates and at different times for Demand Response Resources associated with a Demand Response Capacity Resource if the Demand Response Resources have different offer parameters. In addition, the ISO will only schedule Demand Resource Commercial Operation Audits of a Demand Response Resource with Demand Response Assets that do not have an Audited Demand Reduction value.

(c) New Demand Response Asset Audits will be performed following the request of the Market Participant. The request for a New Demand Response Asset Audit by the Market Participant shall be made during the last seven days of the month. The audit will be performed on Business Days during the month following the date of the request by the Market Participant. The date and time of the audit will be unannounced. An audit request may be denied by the ISO, and an audit may be rescheduled, if its performance will jeopardize the reliable operation of the electrical system.

III.13.6.1.5.4.8. New Demand Response Asset Audits

A Market Participant may request a New Demand Response Asset Audit for all New Demand Response Assets that are mapped to a Demand Resource. The results of a New Demand Response Asset Audit may be used:

(a) In calculating the Seasonal DR Audit value for the Demand Resource to which the asset is mapped until the next Seasonal DR Audit for the full Demand Resource is conducted;

(b) In calculating the commercial capacity value of the Demand Resource for purposes of determining release of financial assurance pursuant to Section III.13.1.9.2.2, until the next Demand Resource Commercial Operation Audit is conducted;

(c) For determination regarding termination under Section III.13.3.4(c); and

(d) In the monthly calculation of a Demand Resource's Demand Reduction Value pursuant to Section III.13.7.1.5.7 and Section III.13.7.1.5.8.

When a New Demand Response Asset Audit is performed, the commercial capacity value and Seasonal DR Audit value of the Demand Resource to which the asset is mapped shall be updated to reflect any changes in the composition of the Demand Resource.

III.13.6.1.5.4.8.1. General Auditing Requirements for New Demand Response Assets.

(a) A New Demand Response Asset Audit will be conducted by simultaneously evaluating the performance of each New Demand Response Asset that is mapped to that Demand Resource.

(b) A New Demand Response Asset Audit is valid beginning with the month in which the audit is performed, and remains valid until the next Seasonal DR Audit is performed for a like season or until a

Demand Resource Commercial Operation Audit is performed. Additional audits performed in a month shall not replace the results of the initial audit conducted in a month and are valid on the first of the month following the audit. Audit results shall not be used in the calculation of a Demand Reduction Value that is based on Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours.

III.13.6.1.5.5. Reporting of Forecast Hourly Demand Reduction.

A Market Participant with Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO a two-day forecast of each Demand Resource's Forecast Hourly Demand Reduction for each Operating Day. The Market Participant shall update its forecast, in accordance with the ISO New England Manuals and Operating Procedures, to reflect its estimate of each Demand Resource's Forecast Hourly Demand Reduction.

III.13.6.1.5.6. Reporting of Monthly Maximum Forecast Hourly Demand Reduction.

A Market Participant with Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO each month a forecast of each resource's monthly maximum Forecast Hourly Demand Reduction for each of the next 12 months.

III.13.6.2. 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.13.6.2, and shall not be subject to the requirements set forth in Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.13.6.2.1. Generating Capacity Resources.

III.13.6.2.1.1. 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.

III.13.6.2.1.1.1. 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.13.6.2.1.1.2. Real-Time Energy Market Participation.

A Generating Capacity Resource having no 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, must Self-Schedule in order to participate 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.13.6.2.1.2. 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 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.13.6.2.2. [Reserved.]

III.13.6.2.3. Intermittent Power Resources.

III.13.6.2.3.1. 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.

III.13.6.2.3.2. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources 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.13.6.2.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.2.4.1. Energy Market Offer Requirements.

A Settlement Only Resource may not submit an offer into the Day-Ahead Energy Market or the Real-Time Energy Market.

III.13.6.2.4.2. Additional Requirements for Settlement Only Resources.

Settlement Only Resources 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;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.2.5. Demand Resources.

III.13.6.2.5.1. Energy Market Offer Requirements.

Real-Time Emergency Generation Resources, Seasonal Peak and On-Peak Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand

Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E1. A Market Participant with a Demand Response Resource associated with a Demand Response Capacity Resource ~~and associated Net Supply Generator Assets,~~ 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.

For Demand Reduction Offers made into the Day-Ahead Energy Market and Real-Time Energy Market ~~from~~ for such Demand Response Resources, the sum of the Demand Response Resource's Minimum Reduction Time plus the Minimum Time Between Reductions must also be less than or equal to 24 hours.

~~For Supply Offers made into the Day-Ahead Energy Market and Real-Time Energy Market from such Net Supply Generator Assets, the sum of the Minimum Run Time plus the Minimum Down Time must also be less than or equal to 24 hours.~~

III.13.6.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with a Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response Capacity Resource without a Capacity Supply Obligation, may submit a Demand Reduction Offer ~~or, for any associated Net Supply Generator Asset, a Supply Offer,~~ into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer ~~or Supply Offer~~ clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer ~~or Supply Offer~~, up to the Maximum Reduction ~~or 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 Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with a Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response 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 ~~or, for any associated Net Supply Generator Assets, a Supply 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.13.6.2.5.2. Additional Requirements for Demand Response Capacity Resources Having No Capacity Supply Obligation.

Demand Response Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in Section III.13.6.1.5.4 and 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. Demand Response Capacity Resources having no 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.13.6.3. 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.13.6.3 and the ISO New England Manuals. Intermittent Power Resources, Settlement Only Resources, and Demand 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.

III.13.6.4. ISO Requests for Energy.

The ISO may request that a Demand Response Capacity Resource or Generating 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 Section III.13 of this Tariff by such a request to provide energy from that capacity, and shall not be subject to any availability penalties under Section III.13 of this Tariff by such a request for failure to provide energy from that capacity that is not subject to a Capacity Supply Obligation. 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.13.6.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.13.6.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

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III.13.7. Performance, Payments and Charges in the FCM.

During each month within each Capacity Commitment Period ("Obligation Month"), each resource that acquired or shed a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will be subject to payments, charges, penalties and adjustments for such activity. In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month shall have their performance measured throughout the month, based on the resource's availability during any Shortage Events in the Obligation Month.

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. Performance Measures.

III.13.7.1.1. Generating Capacity Resources.

During each Capacity Commitment Period, each Generating Capacity Resource having a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will have its performance measured during each Obligation Month based on the resource's availability during any Shortage Events during the month.

III.13.7.1.1.1. Definition of Shortage Events.

(a) In all Capacity Zones, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for Ten-Minute Non-Spinning Reserves shall be a Shortage Event.

(b) Prior to June 1, 2017, in any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for the "minimum TMOR" requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement (described in Section III.2.7A(c)) when Action 2 under Operating Procedure No. 4 has also been implemented for the entire Capacity Zone shall also be a Shortage Event. Beginning on June 1, 2017, in any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for the "minimum TMOR" requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement (described in Section III.2.7A(c)) shall also be a Shortage Event.

(c) Prior to June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be Action 2 under Operating Procedure No. 4, or any Operating Procedure No. 7 event, that is declared for the entire import-constrained Capacity Zone for thirty or more contiguous minutes and that is not also declared for the entire Rest-of-Pool Capacity Zone. Beginning on June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for the local Thirty-Minute Operating Reserves requirement (described in Section III.2.7A(c)) that is declared for the entire import-constrained Capacity Zone.

(d) In all cases, to be considered discrete Shortage Events, such events must be separated by at least 2.5 hours. Events that would satisfy the definition of Shortage Events except that they are separated by less than 2.5 hours shall be considered a single Shortage Event with a duration equal to the sum of the lengths of the underlying events. There shall be no more than two Shortage Events per Capacity Zone per day. If there are more than two Shortage Events in a day, only the first two Shortage Events that occur will be recognized.

(e) For the purposes of Section III.13.7.1.1.1(d), Shortage Events that cross daily boundaries will be considered to occur on the day in which the Shortage Event was triggered. Availability during Shortage Events that cross monthly boundaries will be applied to the Obligation Month in which the Shortage Event was triggered.

III.13.7.1.1.1.A Shortage Event Availability Score.

For each Shortage Event, the ISO shall calculate a Shortage Event Availability Score for each resource, as follows: For each hour containing any portion of the Shortage Event, the ISO shall multiply the resource's hourly availability score by the number of minutes of the Shortage Event in that hour, and then divide the product by the total number of minutes in the Shortage Event. The resulting values for each hour shall then be added together to determine the resource's Shortage Event Availability Score.

III.13.7.1.1.2. Hourly Availability Scores.

The ISO shall calculate an availability score for each resource for each hour that contains any portion of a Shortage Event. A resource's availability score for an hour, expressed as a percentage which may not exceed 100 percent, shall be the sum of the resource's available MW in that hour plus any adjustments pursuant to Section III.13.7.1.1.4 divided by the resource's Capacity Supply Obligation. In the event that there are no Shortage Event hours during a month, no availability penalties will be assessed.

III.13.7.1.1.3. Hourly Available MW.

A resource's available MW in each hour that contains any portion of a Shortage Event shall be determined pursuant to the provisions of this Section III.13.7.1.1.3, provided, however, that in no case shall a resource's available MW in an hour exceed that resource's CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales from that resource).

(a) For a resource that is on-line with a metered output greater than zero and following ISO dispatch instructions, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(b) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification time plus cold start time of thirty minutes or less, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(c) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification plus cold start-up time of less than or equal to 12 hours (16 hours, during the first five Capacity Commitment Periods for resources with notification plus start-up times greater than 12 hours as of June 16, 2006) and the output, up to the Capacity Supply Obligation, was competitively offered into the Energy Market (i.e., capacity from the listed portion of the resource was offered at or below the appropriate Reference Level plus applicable conduct thresholds) but was not committed by the ISO and was consequently unavailable within 30 minutes, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(d) For a resource that is off-line but not meeting the requirements of either Section III.13.7.1.1.3(b) or Section III.13.7.1.1.3(c), the available MW in an hour shall be zero.

(e) For a resource that is on-line but not able to follow ISO dispatch instructions, the available MW in an hour shall be the resource's metered output for the hour.

(f) Where a resource is not committed due to an outage or derate of transmission equipment within the New England Control Area, other than an outage or de-rate of transmission equipment that is controlled by the owner of the resource or that constitutes a radial lead to a resource in the New England Control Area (other than radial leads to Wyman 4 and Stony Brook), that resource's available MW in an hour shall not be reduced as result. Maine Independence Station shall be considered available when derated or not committed because of a transmission constraint.

(g) Where a resource is denied a self-schedule request by the ISO and therefore was not available in the Real-Time Energy Market, that resource's available MW in an hour shall not be reduced as a result.

(h) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation and cannot conduct its capability audit by the first day of the Obligation Month, that resource's available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(i) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, that resource's available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(j) Where a resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), that resource will have its hourly available MW reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

III.13.7.1.1.4. Availability Adjustments.

(a) A resource's hourly availability score may be increased using a Supplemental Availability Bilateral as described in Section III.13.5.3. Where all of the requirements of Section III.13.5.3 are met, the amount of available MW from the Supplemented Capacity Resource during each hour of the Shortage Event will be increased by the amount of supplemental capacity specified in the Supplemental Availability Bilateral, provided, however, that only available capacity above the Supplemental Capacity

Resource’s Capacity Supply Obligation, if any, during each hour of the Shortage Event may be counted as supplemental capacity for the Supplemented Capacity Resource. The sum of these amounts will be counted in determining the availability score of the Supplemented Availability Resource for the Shortage Event.

(b) A resource’s hourly availability score may be increased when an asset associated with the resource is on a planned outage that was approved in the ISO’s annual maintenance scheduling process. Market Participants may indicate when submitting a planned outage request that the outage is to be considered exempt as described in ISO New England Operating Procedure No. 5. In such cases the associated resource’s hourly available MWs may be increased by an amount up to the outage MWs requested, provided that the resource has not exceeded the maintenance allotment hour limit regarding exempt approved planned outages at the time of the Shortage Event as described in the ISO New England Manuals. In the case of a Settlement Only Resource, a planned outage scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource’s hourly availability score as described in this subsection.

III.13.7.1.1.5. Poorly Performing Resources.

Prior to the Forward Capacity Auction qualification process, the ISO shall determine whether a resource meets the following two criteria: in the most recent four consecutive Capacity Commitment Periods or the most recent 4 years in which the resource assumed a Capacity Supply Obligation: (a) the resource received 3 annual availability scores of less than or equal to 40 percent; and (b) the resource has failed to be available in its entirety during ten or more Shortage Events during that same period. The annual availability score for each Capacity Commitment Period shall be equal to the average of all availability scores as calculated for each hour during each Shortage Event. If both of these criteria are met, the resource shall be considered a Poorly Performing Resource and shall not be eligible to participate in any subsequent Forward Capacity Auctions, and may not assume an obligation through the reconfiguration auctions, or Capacity Supply Obligation Bilaterals until it either achieves an availability score of 60 percent or higher in three consecutive Capacity Commitment Periods or 3 consecutive years, or demonstrates to the ISO that the reasons for the inadequate availability scores have been remedied. For the purposes of determining whether a resource is a Poorly Performing Resource, its availability score while it is de-listed shall not be considered. For the purposes of returning from poorly performing status, the ISO, at the request of the resource owner, may consider performance while de-listed, but in no case shall the ISO use non-consecutive years for evaluating a resource’s performance.

III.13.7.1.2. Import Capacity.

The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as defined in Section III.13.7.1.1.1. An Import Capacity Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1, as appropriate). An Import Capacity Resource's available MW in each hour that contains any portion of a Shortage Event shall be determined as follows:

(a) Where the corresponding External Transactions are delivering energy in accordance with ISO dispatch instructions, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(b) Where the corresponding External Transactions have been offered in accordance with the provisions of Section III.13.6.1.2 and is not delivering energy during the hour because the ISO has not requested dispatch of the transaction, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(c) Where the corresponding External Transactions have not been offered in accordance with the provisions of Section III.13.6.1.2 or have been offered in accordance with the provisions of Section III.13.6.1.2 and are not delivering energy during the hour despite ISO requested dispatch of the transaction, the resource's available MW in the hour shall be zero.

(d) Where the Import Capacity Resource was offered in accordance with the provisions of Section III.13.6.1.2 but cannot make Real-Time deliveries of energy because the relevant external interface is already flowing at its Total Transfer Capability into New England in Real-Time, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

III.13.7.1.2.1. Availability Adjustments.

The hourly availability score of an Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource is on a planned outage in the same manner as described in Section III.13.7.1.1.4(b).

III.13.7.1.3. Intermittent Power Resources.

The performance measure for Intermittent Power Resources, including Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.4. Settlement Only Resources.

III.13.7.1.4.1. Non-Intermittent Settlement Only Resources.

A Non-Intermittent Settlement Only Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively. Its available MW in an hour of a Shortage Event shall be the resource's metered output for the hour.

III.13.7.1.4.2. Intermittent Settlement Only Resources.

The performance measure for Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.5. Demand Resources.

III.13.7.1.5.1. Capacity Values of Demand Resources.

The Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, multiplied by one plus the percent average avoided peak transmission and distribution losses used by the ISO in its calculations of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. Beginning with the Capacity Commitment Period starting June 1, 2012 the Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by one plus the percent average avoided peak transmission and distribution losses used to calculate the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. For the first Forward Capacity Auction, the value of the Installed Capacity Requirement divided by the 50/50 summer system peak load forecast shall be 1.143, and one plus the percent average avoided peak transmission and distribution losses shall be 1.08.

III.13.7.1.5.1.1. Special Provisions for Demand Resources that Cleared in the First through Seventh Forward Capacity Auctions in which Project Sponsor Elected to have its Capacity Supply Obligation and Capacity Clearing Price Apply for Multiple Capacity Commitment Periods.

For a Demand Resource that cleared in the Forward Capacity auction for the Capacity Commitment Period beginning June 1, 2010 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2010, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.143 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2011, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.161 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for any of the Capacity Commitment Periods beginning June 1, 2012 through the Capacity Commitment Period beginning in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply in a future Capacity Commitment Period, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.08. This special provision shall cease to apply once the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.2. Capacity Values of Certain Distributed Generation.

For those Distributed Generation resource assets that are capable of generating energy in excess of the facility load and capable of delivering the excess generation to the power grid, if across Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, as appropriate, a Distributed Generation resource asset's monthly average hourly output is greater than the monthly average hourly load of the end-use customer to which the resource is directly connected, the Capacity Value of the portion of output exceeding the customer's load for the month will be the Demand Reduction Value for that portion of the output. No average avoided peak transmission and distribution losses shall be applied to Net Supply associated with a Demand Response Asset, Demand Response Resource, or Demand Response Capacity Resource.

III.13.7.1.5.3. Demand Reduction Values.

A Demand Reduction Value is a quantity of reduced demand produced by a Demand Resource and is calculated pursuant to Section III.13.7.1.5.4, III.13.7.1.5.5, III.13.7.1.5.6, III.13.7.1.5.7 and III.13.7.1.5.8.

III.13.7.1.5.4. Calculation of Demand Reduction Values for On-Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of On-Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource On-Peak Hours in the month.

III.13.7.1.5.4.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. The summer seasonal Demand Reduction Value shall apply to the months of September, October, November, April and May.

III.13.7.1.5.4.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. The winter seasonal Demand Reduction Value shall apply to the months of February and March.

III.13.7.1.5.5. Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource Seasonal Peak Hours in the month. If there are no Demand Resource Seasonal Peak Hours in the months of July, August, or January, the Demand

Reduction Value for those months shall be equal to: (i) the Demand Reduction Value established for the previous month if the previous month's Demand Reduction Value was calculated using Seasonal Peak Hours or (ii) the Seasonal DR Audit results if the Demand Reduction Value for the previous month was not calculated using Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) where there was no audit conducted in the month, the applicable previous seasonal Demand Reduction Value.

III.13.7.1.5.5.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. This summer seasonal Demand Reduction Value will apply to the months of September, October, November, April and May.

III.13.7.1.5.5.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. This winter seasonal Demand Reduction Value will apply to the months of February and March.

III.13.7.1.5.6. [Reserved.]

III.13.7.1.5.6.1. [Reserved.]

III.13.7.1.5.6.2. [Reserved.]

III.13.7.1.5.7. Demand Reduction Values for Real-Time Demand Response Resources.
Demand Reduction Values are determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Demand Response Resource is the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of July, August, or January, the Demand Reduction Value of that resource for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous month's Demand Reduction Value was calculated using Real-Time Demand Response Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Demand Response Event Hours. If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of June or December the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month.

III.13.7.1.5.7.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of a Real-Time Demand Response Resource for September, October, November, April and May shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Values in the most recent months of June, July and August and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of a Real-Time Demand Response Resource for February and March shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of December and January if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Value in the most recent months of December and January and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Demand Response Resource receiving a Dispatch Instruction for a Real-Time Demand Response Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Demand Response Resource's Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the

Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Demand Response Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.7.3.1. Determination of the Hourly Real-Time Demand Response Resource Deviation.

An Hourly Real-Time Demand Response Resource Deviation shall be calculated for each Real-Time Demand Response Resource as the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Demand Response Event Hour. The calculation of the Hourly Real-Time Demand Response Resource Deviation shall be determined in a manner that reflects that Real-Time Demand Response Resources are allowed 30 minutes from the beginning of the first Real-Time Demand Response Event Hour in consecutive Real-Time Demand Response Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in the Dispatch Instruction when such resources are dispatched in response to Real-Time Demand Resource Dispatch Hours. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Demand Response Resource Deviation is greater than zero in any Real-Time Demand Response Event Hour, the Hourly Real-Time Demand Response Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Load Zone in the hour or, starting on June 1, 2011, in the same Dispatch Zone in the hour.

III.13.7.1.5.8. Demand Reduction Values for Real-Time Emergency Generation Resources. Demand Reduction Values shall be determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Emergency Generation Resource shall be the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous months Demand Reduction Value was calculated using Real-Time Emergency Generation Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resouce in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Emergency Generation Event Hours. If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resouce in that month.

III.13.7.1.5.8.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value for the months of September, October, November, April and May shall be equal to the simple average of the Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of September, October, November, April or May, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8, during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value for the months of February and March shall be equal to the simple average of the Demand Reduction Values in the most recent months of December and January if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of February or March, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8 during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Emergency Generation Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Emergency Generation Resource receiving a Dispatch Instruction for a Real-Time Emergency Generation Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Emergency Generation Resource's Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Emergency Generation Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.8.3.1. Determination of the Hourly Real-Time Emergency Generation Resource Deviation.

An Hourly Real-Time Emergency Generation Resource Deviation shall be calculated for each Real-Time Emergency Generation Resource as the difference between the Average Hourly Output or Average Hourly Load Reduction of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Emergency Generation Event Hour. The calculation of the Hourly Real-Time Emergency Generation Resource Deviation shall be determined in a manner that reflects that Real-Time Emergency Generation Resources are allowed 30 minutes from the beginning of the first Real-Time Emergency Generation Event Hour in consecutive Real-Time Emergency Generation Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in a Dispatch Instruction. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency

Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Emergency Generation Resource Deviation is greater than zero in any Real-Time Emergency Generation Event Hour, the Hourly Real-Time Emergency Generation Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Dispatch Zone in the hour.

III.13.7.1.5.9. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources and Real-Time Emergency Generation Resources Starting with the Capacity Commitment Period beginning June 1, 2012.

Starting with the Capacity Commitment Period beginning June 1, 2012, the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3, which is equal to the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, shall be eliminated from the determination of Hourly Calculated Demand Resource Performance Values, with the exception of Demand Resources that cleared in the Forward Capacity Auctions for the Capacity Commitment Periods beginning June 1, 2010 and June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared. For Demand Resources with such multi-year Capacity Supply Obligations the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3 shall continue to apply until the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.10. Demand Response Capacity Resources.

The performance of a Demand Response Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as defined in Section III.13.7.1.1.1. A Demand Response Capacity Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1). For the portion associated with the ability to reduce ~~demand~~load at the Retail Delivery Point, availability for Demand Response Capacity Resources would be adjusted for average avoided peak transmission and distribution losses as described in Section III.13.7.1.5.1 and Section III.13.7.1.5.1.1. For the portion associated with the ability to provide Net Supply, availability for Demand Response Capacity Resources would not be adjusted for average avoided peak transmission and distribution losses.

III.13.7.1.5.10.1 Hourly Available MW.

A Demand Response Capacity Resource's available MW in each hour that contains any portion of a Shortage Event shall be determined based upon the sum of its associated Demand Response Resources as follows, provided, that in no case shall a Demand Response Capacity Resource's available MW in an hour exceed that resource's Qualified Capacity from the Forward Capacity Auction for the current Capacity Commitment Period per Section III.13.1.4.1. For purposes of the following calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced,~~ any Net Supply of a Net Supply Generator Asset located at the same Retail Delivery Point, hourly Desired Dispatch Point and Economic Maximum Limit of the Net Supply Generator Asset, shall be reducted by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset~~ the calculated demand reduction of the Demand Response Asset measured at the Retail Delivery Point shall be reduced by the Real-Time Emergency Generation Asset's output.

(a) For a Demand Response Resource that ~~reduces~~ produces a demand reduction and is following Dispatch Instructions ~~and for any associated Net Supply Generator Assets that are following Dispatch Instructions~~ where the ~~total~~ Desired Dispatch Point for the Demand Response Resource ~~and the associated Net Supply Generator Assets~~ is less than ~~(~~the Maximum Reduction ~~plus the Economic Maximum Limit for any associated available Net Supply Generator Assets)~~ and greater than or equal to the Minimum Reduction, the available MW in an hour shall be the greater of (i) the resource's Real-Time Demand Reduction Obligation ~~plus the Net Supply for any associated available Net Supply Generator Assets)~~ and (ii) the lesser of ~~(~~the resource's Demand Response Baseline as adjusted pursuant to Section III.8B.5 plus the ~~Economic Maximum Limit for any associated available Net Supply Generator Assets)~~Net Supply Limit, the resource's Hourly Adjusted Audited Demand Reduction, or ~~(~~the resource's Maximum Reduction as submitted or redeclared by the Lead Market Participant for the resource~~ plus the Economic Maximum Limit for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant)~~.

(b) For a Demand Response Resource that ~~reduces~~ produces a demand reduction and is following Dispatch Instructions ~~and for any associated Net Supply Generator Assets that are following Dispatch Instruction~~ where the ~~total~~ Desired Dispatch Point for the Demand Response Resource ~~and the associated Net Supply Generator Assets~~ is equal to the Maximum Reduction ~~plus the Economic Maximum Limit for any associated available Net Supply Generator Assets) or (Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets equals Minimum Reduction plus Economic Minimum Limit for any associated available Net Supply Generator Assets)~~ or ~~total~~ the Desired Dispatch Point for the Demand Response Resource ~~and the associated Net Supply Generator Assets~~ is less than the Minimum Reduction ~~plus Economic Minimum Limit for any associated available Net Supply Generator Assets~~, the available MW in an hour shall be the resource's Real-Time Demand Reduction Obligation plus any associated Net Supply.

(c) For a Demand Response Resource that has ~~reduced~~ produced a demand reduction ~~or any associated Net Supply Generator Assets have been dispatch~~ but ~~are~~ is not ~~responding~~ following ~~to~~ Dispatch Instructions where the Real-Time Demand Reduction Obligation ~~plus any associated Net Supply~~ is less than the ~~total~~ Desired Dispatch Point for the Demand Response Resource ~~and the associated Net Supply Generator Assets~~, the available MW in an hour shall be the resource's Real-Time Demand Reduction Obligation ~~plus any associated Net Supply~~ for the hour.

(d) For a Demand Response Resource that has ~~reduced~~ produced a demand reduction ~~or any associated Net Supply Generator Assets that have been dispatch~~ but ~~are~~ is not ~~responding to~~following Dispatch Instructions where the Real-Time Demand Reduction Obligation is greater than the ~~total~~ Desired Dispatch Point for the Demand Response Resource ~~and the associated Net Supply Generator Assets~~, the available MW in an hour shall be the lesser of the resource's Real-Time Demand Reduction Obligation ~~plus any associated Net Supply~~ and Hourly Adjusted Audited Demand Reduction for the hour.

(e) For a Demand Response Resource that is not ~~reducing~~ producing a demand reduction, is available for dispatch and is able to respond to Dispatch Instructions, and has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) and an Audited Full Reduction Time (adjusted for the Maximum Reduction ~~and Economic Maximum Limit for any associated available Net Supply Generator Assets~~) of thirty minutes or less, the available MW in an hour shall be the lesser of ~~(the lesser of (~~the resource's (i) Maximum Reduction, as submitted or redeclared by the Lead Market Participant, ~~and~~ (ii) Actual Load plus the Net Supply Limit~~) plus the sum of the Economic Maximum Limits for any~~

~~associated available Net Supply Generator Assets as submitted or redeclared by the Lead market Participant)~~ or (iii) Hourly Adjusted Audited Demand Reduction.

(f) For a Demand Response Resource that is not ~~reducing~~ producing a demand reduction, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction ~~and Economic Maximum Limit for any associated available Net Supply Generator Assets~~ as submitted or redeclared by the Lead Market Participant) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than thirty minutes and less than or equal to 12 hours, the available MW shall be zero unless the duration of the Shortage Event exceeds the Audited Full Reduction Time (adjusted for the Maximum Reduction ~~and Economic Maximum Limit for any associated available Net Supply Generator Assets~~) and Offered Full Reduction Time (adjusted for the Audited Demand Reduction), in which case the available MW in an hour shall be the lesser of ~~(the lesser of~~ (i) the resource's Maximum Reduction, as submitted or redeclared by the Lead Market Participant, (ii) the resource's Actual Load plus ~~Economic Maximum Limits for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant~~its Net Supply Limit or (iii) the resource's Hourly Adjusted Audited Demand Reduction time weighted to reflect the portion of the hour in which the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time exceeded the Shortage Event duration.

(g) For a Demand Response Resource that (i) is not ~~reducing~~ producing a demand reduction, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets~~) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than 12 hours or (ii) is unavailable to reduce demand, the available MW shall be zero.

III.13.7.1.5.10.1.1 Adjusted Audited Demand Reduction.

A Demand Response Resource's Adjusted Audited Demand Reduction shall be determined as follows. For purposes of these calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the ~~Economic Maximum Limit of the Net Supply Generator Asset at the same location~~Maximum Reduction shall be reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset:

(a) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) equal to its Audited Full Reduction Time (adjusted for the Maximum Reduction ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets~~) shall have its Adjusted Audited Demand Reduction set equal to the resource's Audited Demand Reduction.

(b) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than its Audited Full Reduction Time (adjusted for the Maximum Reduction ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets~~) shall have its Adjusted Audited Demand Reduction calculated as:

((the Audited Full Reduction Time adjusted for the ~~(~~Maximum Reduction ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets)~~) divided by (the Offered Full Reduction Time adjusted for the Audited Demand Reduction)) multiplied by the lesser of ~~(~~the Audited Demand Reduction or ~~(~~Maximum Reduction as submitted or redeclared by the Lead Market Participant ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets))~~.

(c) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) less than its Audited Full Reduction Time (adjusted for the Maximum Reduction ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets~~) shall have its Adjusted Audited Demand Reduction calculated as:

((the Offered Full Reduction Time adjusted for the Audited Demand Reduction) divided by (the Audited Full Reduction Time adjusted for the ~~(~~Maximum Reduction ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets)~~)) multiplied by the lesser of ~~(~~the Audited Demand Reduction or ~~(~~Maximum Reduction as submitted or redeclared by the Lead Market Participant ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets))~~.

III.13.7.1.5.10.1.2 Hourly Adjusted Audited Demand Reduction.

The Hourly Adjusted Audited Demand Reduction shall be calculated as the time weighted average of the Adjusted Audited Demand Reduction and Audited Demand Reduction for the period the resource was dispatched.

III.13.7.1.5.10.2 Availability Adjustments.

The hourly availability score of a Demand Response Capacity Resource shall be increased in the same manner as described in Section III.13.7.1.1.4(a). The hourly availability score of a Demand Response Capacity Resource comprised of an aggregation of one or more Demand Response Resources shall be adjusted as described in Section III.13.7.1.1.4(b). In the case of Demand Response Resources comprised of an aggregation of one or more Demand Response Assets with a demand reduction and any Net Supply of less than 5 MW achieved by the asset in the most recent seasonal audit of the associated Demand Response ~~Capacity~~ Resource, a planned outage of the equipment used to produce the demand reduction scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource's hourly availability score as described in Section III.13.7.1.1.4(b).

In addition, the hourly availability score of a Demand Response Capacity Resource shall be increased as described in this subsection:

(a) A Demand Response Capacity Resource's hourly availability score shall be increased, subject to verification by the ISO, when one or more Demand Response Assets of a Demand Response Resource associated with the Demand Response Capacity Resource is on a forced curtailment or scheduled curtailment.

(i) A forced curtailment can be submitted to the ISO as described in the ISO New England Manuals for any reductions in demand that occur as a result of actions outside the control of the Demand Response Asset that is subject to the forced curtailment. The forced curtailment can be submitted or revised during the resettlement process and cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response ~~Capacity~~ Resource.

(ii) A scheduled curtailment must be submitted to the ISO at least ~~15~~ seven calendar days ahead of the start of the curtailment to be eligible for an adjustment for any reductions in load that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Demand Response Assets with a Maximum Interruptible Capacity of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The scheduled curtailment cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response ~~Capacity~~ Resource. Scheduled curtailments must be a minimum of a single calendar day, and shall not exceed a total of 14 calendar days per Capacity Commitment Period.

(b) The sum of the availability adjustments for an hour may not exceed:

(i) for a Demand Response Resource that has received a Dispatch Instruction to reduce its demand, the lesser of (x) the resource's Demand Response Baseline as adjusted pursuant to Section III.8B.5 ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets)~~ and (y) Audited Demand Reduction adjusted down by the greater of (1) the Maximum Reduction, as submitted or redeclared by the Lead Market Participant ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets)~~, or (2) Real-Time Demand Reduction Obligation ~~plus Net Supply for any associated Net Supply Generator Asets)~~. For purposes of this calculation, when the output of a Real-Time Emergency Generation Asset at the same location exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point, any Net Supply and the ~~Economic Maximum Limit~~Maximum Reduction of the ~~Net Supply Generator Asset at the same location~~Demand Response Asset shall be reduced by the difference between the Real-Time Emergency Generation Asset's output and adjusted Demand Response Baseline of the Demand Response Asset.

(ii) for a Demand Response Resource that has not received a Dispatch Instruction to reduce its demand, the lesser of (i) the resource's Actual Load plus ~~Economic Maximum Limit for any associated available Net Supply Generator Assets, as submitted or redeclared by the Lead Market Participant)~~Net Supply Limit, ~~and~~ or (ii) the Audited Demand Reduction adjusted down by (the Maximum Reduction, as submitted or redeclared by the Lead Market Participant ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets, as submitted or redeclared by the Lead Market Participant)~~.

III.13.7.1.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources are subject to the availability penalties and credits as defined by their resource type.

III.13.7.2. Payments and Charges to Resources.

Resources acquiring or shedding a Capacity Supply Obligation shall be subject to payments and charges in accordance with this Section III.13.7.2. Such resources will also be subject to adjustments as detailed in Section III.13.7.2.7.

III.13.7.2.1. Generating Capacity Resources.

III.13.7.2.1.1. Monthly Capacity Payments.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

(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 (or in the case described in Section III.13.7.1.1.3(i), the lesser of the resource's Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted pursuant to Section III.13.2.7.3(b) and 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 (the "FCA Payment"). 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 four 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.

III.13.7.2.2. Import Capacity.

Import Capacity Resources shall receive monthly capacity payments utilizing the same methodology as that used for Generating Capacity Resources set forth in Section III.13.7.2.1.

III.13.7.2.2.A. 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 (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

> 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.13.7.3.1.

III.13.7.2.3. Intermittent Power Resources.

An Intermittent Power Resource shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section 13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Power Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.4. Settlement Only Resources.

III.13.7.2.4.1. Non-Intermittent Settlement Only Resources.

Non-Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1.

III.13.7.2.4.2. Intermittent Settlement Only Resources.
Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Settlement Only Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.5. Demand Resources.

III.13.7.2.5.1. Monthly Capacity Payments for All Resources Except Real-Time Emergency Generation Resources.
For all Demand Resources except for Real-Time Emergency Generation Resources, the monthly payment shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1.

III.13.7.2.5.2. Monthly Capacity Payments for Real-Time Emergency Generation Resources.
For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f).

III.13.7.2.5.3. Energy Settlement for Real-Time Demand Response Resources
A Market Participant with Real-Time Demand Response Assets associated with a Real-Time Demand Response Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E1.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Demand Response Resource is located. The demand reduction paid or charged shall be net of the Real-Time Demand Reduction Obligation of Real-Time Demand Response Assets that are part of the Real-Time Demand Response Resource that received payment pursuant to Sections III.E1.9.2.1 or III.E1.9.2.2 for the same dispatch or audit period. Demand reductions eligible for payments or charges pursuant to

this section shall be those produced during Real-Time Demand Response Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4. Energy Settlement for Real-Time Emergency Generation Resources

A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions or generator output, adjusted as described in Section III.E1.8.3 or III.13.7.2.5.4.1 and for the percent average avoided peak distribution losses for the portion of the asset reducing demand, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing prior to June 1, 2017, and at the Real-Time LMP for the Dispatch Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing on or after June 1, 2017. Demand reductions or generator output eligible for payments or charges pursuant to this section shall be those produced during Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4.1 Adjustment for Net Supply ~~Generator Assets~~From Real-Time Emergency Generation Assets.

For Capacity Commitment Periods commencing on or after June 1, 2017, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the demand reduction measured at the Retail Delivery Point is first credited to the output of the Real-Time Emergency Generation Asset starting with the Net Supply amount, and any remaining demand reduction is credited to the Demand Response Asset ~~output eligible for payments will be set equal the adjusted Demand Response Baseline of the Demand Response Asset~~. The Net Supply amount shall not be multiplied by one plus the average avoided peak distribution losses. The demand reduction amount shall be multiplied by one plus the average avoided peak distribution losses.

III.13.7.2.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources shall not receive monthly capacity payments for the portion of the resource designated as a Self-Supplied FCA Resource. Charges to load associated with Self-Supplied FCA Resources are calculated pursuant to Section III.13.7.3.

III.13.7.2.7. Adjustments to Monthly Capacity Payments.

Monthly capacity payments to resources with a Capacity Supply Obligation as of the beginning of the Obligation Month will be adjusted as described in Section III.13.7.2.7.1.

III.13.7.2.7.1. Adjustments to Monthly Capacity Payments of Generating Capacity Resources.

III.13.7.2.7.1.1. Peak Energy Rents.

Payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents ("PER") calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone.

III.13.7.2.7.1.1.1. Hourly PER Calculations.

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

Hourly PER($/kW) = [(LMP - Strike Price) * [Scaling Factor] * [Availability Factor]

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.2.7.1.1.2. Monthly PER Application.

(a) The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as follows:

PER Adjustment = the minimum of: (i) the PER cap or (ii) the Average Monthly PER x PER Capacity Supply Obligation.

Where the PER cap for each resource equals the FCA Payment, plus the product of the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same Capacity Commitment Period multiplied by the Capacity Clearing Price applicable to that resource's location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation calculation.

(b) PER shall be deducted from capacity payments independently of availability penalties.

(c) FCA Payment minus PER may not be negative for any month.

III.13.7.2.7.1.2. Availability Penalties.

Availability penalties shall be assessed for each resource with a Capacity Supply Obligation as of the beginning of the Obligation Month. The penalty will be based on the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b) or as described in Section III.13.2.8) in the Capacity Zone in which the resource is located for the relevant Capacity Commitment Period, regardless of whether the resource assumed the Capacity Supply Obligation through a Forward Capacity Auction, a reconfiguration auction, or a Capacity Supply Obligation Bilateral.

For capacity resources that are partially or fully unavailable during a Shortage Event:

(a) Penalties shall be determined and assessed on a resource-specific basis. Penalties shall be calculated for each Shortage Event during an Obligation Month and assessed on a monthly basis, subject to the availability penalty caps outlined in Section III.13.7.2.7.1.3.

(b) The penalty per resource for each Shortage Event shall be equal to:

Penalty = [Resource's Annualized FCA Payment]*PF*[1 – Shortage Event Availability Score]

Where:

Annualized FCA Payment = the relevant Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) multiplied by the resource's Capacity Supply Obligation as of the beginning of the Obligation Month multiplied by 12.

PF = .05 for Shortage Events of 5 hours or less. PF is increased by .01 for each additional hour above 5 hours.

III.13.7.2.7.1.3. Availability Penalty Caps.

The following caps will apply to the total availability penalties assessed to a resource. If a resource with a Capacity Supply Obligation sheds or acquires an obligation outside the relevant Obligation Month, the Annualized FCA Payment shall not be prorated. Caps are resource-specific and partial year assumption or transfer of a Capacity Supply Obligation through Capacity Supply Obligation Bilaterals or reconfiguration auctions does not affect the application of the cap to each resource independently.

(a) **Per Day**. In no case shall the total penalties for all Shortage Events in an Operating Day exceed 10 percent of a resource's Annualized FCA Payment for that Capacity Commitment Period.

(b) **Per Month**. The sum of a resource's penalties arising from unavailability during an Obligation Month may not exceed two and one-half times the Annualized FCA Payment, divided by twelve, for that Obligation Month. The sum of a resource's penalties arising from unavailability due to a single outage of four days or less but spanning two calendar months may not exceed two and one-half times the average of the Annualized FCA Payments, divided by twelve, for both months.

(c) **Per Capacity Commitment Period**. In determining the availability penalties for the Obligation Month, a resource's cumulative availability penalties for a Capacity Commitment Period may not exceed its Annualized FCA Payment (less PER adjustments) for that Capacity Commitment Period.

III.13.7.2.7.1.4. Availability Credits for Capacity Demand Response Capacity Resources, Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources.

On a monthly basis, penalties received from unavailable resources shall be redistributed to Demand Response Capacity Resources, Generating Capacity Resources and Import Capacity Resources with Capacity Supply Obligations and to designated Supplemental Capacity Resources without a Capacity

Supply Obligation that have a valid Supplemental Availability Bilateral (pursuant to Section III.13.5.3.2) that were available (pursuant to Section III.13.7.1.1.3, Section III.13.7.1.5.10.1) in the respective hours on a Capacity Zone basis as follows: For each Obligation Month, the penalties assessed for the Shortage Events during the month will be credited to those resources identified above that were available, in whole or in part, during the Shortage Events, pro-rata by hourly available MW in the relevant Capacity Zones. Self-Supplied FCA Resources shall be eligible to receive their pro rata share of availability penalties paid by other capacity resources.

III.13.7.2.7.2. Import Capacity.

In addition to the adjustment in this section, Import Capacity Resources shall also be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.2.1. External Transaction Offer and Delivery Performance Adjustments.

In the event that the conditions in Section III.13.6.1.2.1 are not met in any hour of an Operating Day, the Import Capacity Resource will be subject to the following:

(a) If in any hour of an Operating Day a priced External Transaction associated with an Import Capacity Resource with a Capacity Supply Obligation is offered above both the offer threshold for the Operating Day and the offer threshold of the prior Operating Day, and for any priced External Transactions from the New York Control Area also is offered above the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the Import Capacity Resource's Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

(b) For every hour of an Operating Day that the total amount offered from all External Transactions associated with an Import Capacity Resource is less than the Import Capacity Resource's Capacity Supply Obligation, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the Capacity Supply Obligation and the total amount of energy offered for that hour and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month. For each Operating Day only the greater of the total penalties in either the Day-Ahead Energy Market or Real-Time Energy Market will be assessed. For the purposes of this section the total energy offered will be adjusted in accordance with Section

III.13.7.1.1.4(b) for any amount that was unavailable due to an outage approved in the ISO's annual maintenance scheduling process.

(c) Except as specified in Section III.13.7.2.7.2.2, for every hour the total energy from an External Transaction associated with an Import Capacity Resource delivered in real-time to the New England Control Area is less than the energy requested, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the quantity requested and the quantity delivered and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month.

Any External Transaction associated with an Import Capacity Resource that is determined to be in economic merit during the next-hour scheduling process will be considered a requested transaction and the ISO may request all or a portion of each transaction.

A Market Participant's total penalty amount for a single Operating Day for each Import Capacity Resource shall be no more than the product of the Import Capacity Resource's Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

Each Obligation Month the penalty amounts from all Market Participants with Import Capacity Resources will be allocated to all Market Participants based on their pro-rata share of Capacity Load Obligation within each Capacity Zone in the Obligation Month, with each Capacity Zone allocated an amount based on the pro-rata share of total capacity credits within each Capacity Zone.

III.13.7.2.7.2.2. Exceptions.

a) No penalty will be assessed if the applicable external interface is fully loaded and the energy from an External Transaction that would otherwise be requested cannot flow. If the transfer capability of the applicable external interface is zero in the import direction it will be considered fully loaded for the purpose of this section.

b) No penalty will be assessed if the delivered energy from a priced External Transaction associated with the New York Control Area is less than requested when the Real-Time Energy Market price at the source location (NYISO Location-Based Marginal Price) is higher than the Real-Time LMP at the associated External Node, provided that Operating Procedure No. 4 has not been declared due to a system-wide capacity deficiency.

c) No penalty will be assessed during periods when the ISO has taken action to reduce import transactions due to a Minimum Generation Emergency condition or due to ramping constraints.

d) No penalty will be assessed on the affected external interface during periods when minimum-flow or directional-flow constraints have occurred, when the ISO was unable to utilize the automated check-out processes for the external interface, or when in-hour curtailments have occurred.

III.13.7.2.7.3. Intermittent Power Resources.

Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.4. Settlement Only Resources.

III.13.7.2.7.4.1. Non-Intermittent Settlement Only Resources.

Non-Intermittent Settlement Only Resources are subject to the same PER adjustments and availability penalties as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.4.2. Intermittent Settlement Only Resources.

Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.5. Demand Resources.

Demand Response Capacity Resources shall be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.5.1. Calculation of Monthly Capacity Variances.

For each month, the Monthly Capacity Variance of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be calculated by subtracting the Demand Resource's Capacity Supply Obligation for the month from the Demand Resource's monthly Capacity Value. If a Demand Resource's Monthly Capacity Variance is zero, the Demand Resource will not be subject to Demand Resource Performance Penalties or Demand Resource Performance Incentives.

III.13.7.2.7.5.2. Negative Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Demand Resource's Monthly Capacity Variance is a negative value, the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be subject to a Demand Resource Performance Penalty equal to the absolute value of the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f). If a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a negative value, the Demand Resource Performance Penalty for such a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be set according to the Capacity Clearing Price applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource (as adjusted pursuant to Section III.13.2.7.3(b)), 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 applicable to the Demand Resource for the particular Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Demand Resource for the particular Capacity Commitment Period.

III.13.7.2.7.5.3. Positive Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource's Monthly Capacity Variance is a positive value, then the Demand Resource shall be eligible to receive a Demand Resource Performance Incentive based on the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period, or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone. If a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a positive value, then the Demand Resource Performance Incentive for such a Demand Resource shall be set according to the Capacity Clearing Price applicable to the Demand Resource for the particular Capacity Commitment Period (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource for the particulate Capacity Commitment Period in effect as of December 31 of the year preceding the Capacity Commitment Period, provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone.

III.13.7.2.7.5.4. Determination of Net Demand Resource Performance Penalties and Demand Resource Performance Incentives.

Demand Resource Performance Penalties and Demand Resource Performance Incentives shall be determined for each Capacity Zone as follows: if the sum of the Demand Resource Performance Penalties in a month in a Capacity Zone is less than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone, then the total amount of Demand Resource Performance Penalties shall be paid on a pro-rata basis, based on the non-prorated Demand Resource

Performance Incentives of each Demand Resource with a positive Monthly Capacity Variance. The total amount of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total amount of the Demand Resource Performance Penalties in the same month in that Capacity Zone.

The total of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total of the Demand Resource Performance Penalties in the same month in that Capacity Zone. If the total Demand Resource Performance Penalties in a month in a Capacity Zone exceeds the total Demand Resource Performance Incentives in the same month in that Capacity Zone, the difference shall not be collected from load serving entities in that Capacity Zone (the ultimate purchaser of capacity).

III.13.7.2.7.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied, but shall be subject to the availability penalties and caps applicable to their resource types.

III.13.7.3. Charges to Market Participants with Capacity Load Obligations.

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.13.7.2 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals), less PER adjustments for resources in the zone as defined in Section 13.7.2.7.1.1, adjusted for any Demand Resource Performance Penalties in excess of Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.4, and including any applicable export charges or credits as determined pursuant to Section III.13.7.2.2.A 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 satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.

III.13.7.3.1. Calculation of Capacity Requirement and Capacity Load Obligation.

The ISO shall assign each load serving entity a Capacity Requirement 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 Capacity Requirement 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) 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 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. The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with pumping of pumped hydro generators, if the resource was pumping; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; net load associated with an Alternative Technology Regulation Resource while providing Regulation and transmission losses associated with delivery of energy over the Control Area tie lines.

A load serving entity's Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the Capacity Zone's Capacity Requirement as calculated above and (ii) the ratio of the sum of the load serving entity's annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period to 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 prior to the start of the Capacity Commitment Period.

A load serving entity's Capacity Load Obligation shall be its Capacity Requirement, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supply FCA Resource designations. A Capacity Load Obligation can be a positive or negative value. A Market Participant that is not a load serving entity shall have a Capacity Load Obligation equal to the net obligation resulting from Capacity Load Obligation Bilaterals, HQICC, and Self-Supply FCA Resource designations.

A Demand Resource's Demand Reduction Value will not be reconstituted into the load of the Demand Resource for the purpose of determining the Capacity Requirement for the load associated with the Demand Resource.

III.13.7.3.1.1. HQICC Used in the Calculation of Capacity Requirements.

In order to treat HQICCs as a load reduction, each holder of HQICCs shall have its Capacity Requirement in the Capacity Zone in which the HQ Phase I/II external node is located as specified in Section III.13.1.3 adjusted by its share of the total monthly HQICC amount.

III.13.7.3.1.2. Charges Associated with Self-Supplied FCA Resources.

The capacity associated with a Self-Supplied FCA Resource shall be treated as a credit toward the Capacity Load Obligation of the load serving entity so designated by such resources as described in Section III.13.1.6. The amount of Self-Supplied FCA Resources shall be determined pursuant to Section III.13.1.6.

III.13.7.3.1.3. 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.13.7.3.2. Excess Revenues.

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.13.7.3.3.

III.13.7.3.3. Capacity Transfer Rights.

III.13.7.3.3.1. Definition and Payments to Holders of Capacity Transfer Rights.

The ISO shall create Capacity Transfer Rights ("CTRs") 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.13.7.3.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER and for Demand Resource Performance Penalties net of Demand Resource Performance Incentives.

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-Supply 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-Supply FCA Resources.

The value of CTRs specifically allocated pursuant to Sections III.13.7.3.3.2(c), III.13.7.3.3.4, and III.13.7.3.3.6 shall be calculated as the product of: (i) the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) for 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. The value of the specifically allocated CTRs will be deducted from the associated Capacity Zone's portion of the CTR fund. The balance of the CTR fund will then be allocated to the load serving entities as set forth in Section III.13.7.3.3.2.

III.13.7.3.3.2. Allocation of Capacity Transfer Rights.

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.13.7.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 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.13.7.3.3.6 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.

(c) **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. Each municipal utility entitlement holder of a resource constructed as a Pool-Planned Unit in Maine shall receive specifically allocated CTRs across the Maine Export Interface equal to the applicable seasonal claimed capability of its ownership entitlements in such unit as described in Section III.13.7.3.3.6. The balance of the CTR fund associated with the Maine Export Interface shall be allocated to load serving entities with a Capacity Load Obligation on the import-constrained side of the Maine Export Interface.

III.13.7.3.3.3. Allocations of CTRs Resulting From Revised Capacity Zones.

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.13.7.3.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 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.13.7.3.3.4. 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.13.7.3.3.2.

(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.13.7.3.3.2.

III.13.7.3.3.5. [Reserved.]

III.13.7.3.3.6. Specifically Allocated CTRs for Pool Planned Units.

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 an initial allocation of CTRs equal to the applicable seasonal claimed capability of the ownership entitlements in such unit. Municipal utility 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	Summer (MW)	Winter (MW)
Nominal Summer (MW)	1155.001	1244.275	104.000	100.000	104.000	67.400	65.300	586.725		
Nominal Winter (MW)	1155.481	1244.275	119.000	116.000	119.000	87.400	85.300	608.575		
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%	58.26	63.73
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%	5.04	5.55
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%	2.93	2.37
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%	15.49	15.64
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%	10.40	11.07
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%	57.69	60.26
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%	82.98	92.77
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%	30.53	32.64
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%	4.53	5.22
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%	4.71	5.35
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	7.63	7.63
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%	5.81	6.61
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%	26.40	30.36
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%	17.01	19.33
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%	15.34	16.63
Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%	24.05	24.12

Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%	10.70	12.28
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%	11.67	13.63
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%	36.93	42.17
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%	21.48	24.45
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%	25.58	29.49
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.33	1.33
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%	4.82	5.53
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%	24.33	26.23
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	10.89	10.90
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%	6.60	7.38
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.25	1.25
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%	10.67	12.27
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%	6.97	7.99
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%	10.18	11.69
Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%	67.51	77.27

This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs 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.

III.13.7.3.4. 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 charge; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund; and (d) any applicable export charges.

SECTION III

MARKET RULE 1

APPENDIX E1

DEMAND RESPONSE

Appendix E1 applies to Capacity Commitment Periods commencing prior to June 1, 2017.

APPENDIX E1

DEMAND RESPONSE

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Appendix E1 applies to Capacity Commitment Periods commencing prior to June 1, 2017.

APPENDIX E1

DEMAND RESPONSE

1. Demand Response Registration

Appendix E1 applies to Capacity Commitment Periods commencing prior to June 1, 2017.

A Market Participant may register a Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis to provide demand reductions during hours ending 0800 through 1800 on non-Demand Response Holiday weekdays subject to the following conditions:

(a) the asset is able to produce at least 100 kW of demand reduction, and;

(b) the metering and communication equipment associated with the asset meets the requirements specified in Section III.E1.2.

A Real-Time Demand Response Asset may consist of an aggregation of multiple end-use metered customers.

1.1 Registration Parameters

During the registration process, Market Participants must submit the following information for each Real-Time Demand Response Asset:

(a) Maximum Interruptible Capacity;

(b) Maximum Load, and;

(c) Maximum Generation, for Real-Time Demand Response Assets that are comprised of Distributed Generation.

1.2 Restrictions on Real-Time Demand Response Asset Registration

A Market Participant may not register and must retire if previously registered a Real-Time Demand Response Asset that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

A Market Participant may not register an existing Generator Asset as a Real-Time Demand Response Asset for the purpose of submitting Demand Reduction Offers.

2. Metering and Communication

2.1 Interval Metering and Telemetry Requirements

The actual metered demand of each individual end-use customer facility that comprises a Real-Time Demand Response Asset must be measured using interval meters located at the individual end-use customer's retail delivery point and shall be reported to the ISO at an interval of five minutes. Actual metered demand submitted to the ISO shall not include average avoided peak distribution losses. ~~Each generator located behind an individual end-use customer's retail delivery point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.~~

Interval meters required pursuant to Section III.E1.2.1 must meet the following requirements:

(a) the interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes ~~or less~~;

(b) if the interval meter is the same meter used by the distribution company for billing purposes, the meter is a revenue-quality meter that is accurate within ± 0.5%, and;

(c) if the interval meter is not the same meter used by the distribution company for billing purposes, the interval meter is either a revenue-quality meter that is accurate within ± 0.5% or a non-revenue-quality meter with an overall accuracy of ± 2.0%. For each non-revenue-quality meter used, the Market Participant must, during the registration process, submit certification from the meter manufacturer that the interval meter being used meets the ± 2.0% accuracy threshold, and shall specify accuracy for the following parameters:

i. current measurement;

ii. voltage measurement;

iii. A/D conversion, and;

iv. calibration.

2.2 Meter Testing

All interval meters must be periodically tested and calibrated.

Market Participants must conduct periodic meter data validation checks.

Market Participants must repair or replace meters that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters and meter data communication systems.

2.3 Auditing

The ISO may, for a Real-Time Demand Response Asset, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and measurement equipment, and witness the demand reduction activities of any facility associated with the asset.

Market Participants must make retail billing meter data from the Host Participant for the facilities associated with a Real-Time Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing, and certifying the metering, data recording and measurement equipment of Real-Time Demand Response Assets.

2.4 Communication/Telemetry

Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facilities comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area. If one or more generators whose output can be controlled is located behind the retail delivery point of the Real Time Demand Response Asset, other than emergency generators that cannot operate synchronized to the electrical grid, then the Market Participant must also submit to the ISO in Real-Time a single set of interval meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

~~For Real-Time Demand Response Assets whose demand reductions are not achieved by Distributed Generation but where there is a generator located behind the retail delivery point, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of all generation.~~

~~For Real-Time Demand Response Assets whose demand reductions are achieved in part or in whole by Distributed Generation, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of Distributed Generation associated with the Real-Time Demand Response Asset.~~

3. Demand Reduction Offers

3.1 Required Demand Reduction Offer Parameters

Market Participants must submit a Demand Reduction Offer for each Real-Time Demand Response Asset that meets the requirements of this section in order to be eligible for a demand reduction payment.

A Demand Reduction Offer must be equal to or greater than the Demand Reduction Threshold Price in effect on the day the Demand Reduction Offer is made.

Demand Reduction Offers reflect the amount of demand reduction offered at the retail delivery point excluding transmission and distribution losses.

A Demand Reduction Offer shall consist of a single offer price in $/MWh (less than or equal to $1000/MWh) and a single demand reduction amount (in MW to the nearest 0.1 MW) that shall apply to hours ending 0800 through 1800 in the Operating Day.

A Market Participant may submit a single Demand Reduction Offer for each of its Real-Time Demand Response Assets for each Operating Day that is a non-Demand Response Holiday weekday.

Demand Reduction Offers for the following Operating Day must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the Operating Day and may not be changed thereafter.

The minimum Demand Reduction Offer amount for each Real-Time Demand Response Asset is 100 kW.

The maximum Demand Reduction Offer amount for each Real-Time Demand Response Asset cannot exceed the asset's Maximum Interruptible Capacity.

Market Participants are prohibited from submitting a Demand Reduction Offer for a Real-Time Demand Response Asset for an Operating Day with a scheduled curtailment, or for an Operating Day with a known forced curtailment. If an unanticipated forced curtailment has occurred, Market Participants are prohibited from submitting a Demand Reduction Offer for the affected Real-Time Demand Response Asset for any subsequent Operating Days until the forced curtailment is over and electrical service to the asset has been restored.

3.2 Optional Demand Reduction Offer Parameters

A Demand Reduction Offer may specify a minimum interruption duration of one to four hours. If a Market Participant does not specify a minimum interruption duration in its Demand Reduction Offer, the minimum interruption duration shall be one hour.

A Demand Reduction Offer may specify a curtailment initiation price (in $ per interruption). If a Market Participant does not specify a curtailment initiation price, the curtailment initiation price shall be $0.

A Demand Reduction Offer must meet the following minimum and maximum price requirements:

(a) The offer price not including the curtailment initiation price shall be greater than or equal to the Demand Reduction Threshold Price; and

(b) The offer cost of the Demand Reduction Offer, which shall include the curtailment initiation price, shall be less than or equal to $1000/MWh. The offer cost shall be computed as follows: offer cost = offer price + [curtailment initiation price/(minimum interruption duration x bid amount (MW))].

4. Day-Ahead Clearing, Scheduling and Notification

Demand Reduction Offers are cleared after the Day-Ahead Energy Market results are determined. Demand Reduction Offers are cleared by comparing the Demand Reduction Offer to the hourly Day-Ahead LMPs for the Load Zone in which the Real-Time Demand Response Asset is located. A Demand Reduction Offer associated with a Real-Time Demand Response Asset will clear in one or more hours of the Operating Day if the sum of the hourly Day-Ahead LMP times the Demand Reduction Offer amount in the cleared hours of the Operating Day is greater than or equal to the sum of the curtailment initiation price for the Operating Day and the sum of the Demand Reduction Offer price times the Demand Reduction Offer amount in the cleared hours of the Operating Day.

The ISO will provide Market Participants with demand curtailment schedules for Real-Time Demand Response Assets based on cleared Demand Reduction Offers.

The demand curtailment schedule shall reflect demand reductions (MW) at the Real-Time Demand Response Asset's retail delivery point.

5. Real-Time Scheduling of Demand Reductions

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for the next Operating Day pursuant to Section III.E1.4. If a Market Participant's Demand Reduction Offer is not cleared Day-Ahead to reduce demand in an hourly time interval for the next Operating Day, the Market Participant may initiate a Real-Time demand reduction by reducing demand when the offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which a Real-Time Demand Response Asset is located.

A Market Participant will not receive a Dispatch Instruction in Real-Time for a Real-Time Demand Response Asset.

5.1 Requirements for Demand Reductions of 5 MW and Above

A Market Participant with a Real-Time Demand Response Asset that has submitted a Demand Reduction Offer for the Operating Day, must request permission from the ISO prior to reducing demand in an amount greater than or equal to 5 MW during a 60 minute period, unless the asset was dispatched or audited pursuant to Section III.13. Permission must be requested not less than 15 minutes and not greater than 60 minutes before the start of the demand reduction. The ISO may approve or deny the requested interruption based on the impact of the interruption on system reliability.

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data 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:

i. 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.

ii. An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer block.

iii. 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.

iv. 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 demand response exceeds the cost to load associated with compensating demand response.

v. The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} \times \frac{FPI_c}{FPI_h}$$

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 resulting 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 preceding month in advance of the Demand Reduction Threshold Price's effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Real-Time Demand Response Assets located anywhere within the New England Control Area.

7. Demand Response Baselines

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8A prior to submitting a Demand Reduction Offer for a Real-Time Demand Response Asset.

A Market Participant shall take no actions to establish a Demand Response Baseline or affect a Demand Response Baseline adjustment that results in a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers absent demand reduction payments.

For Real-Time Demand Response Assets comprised of Distributed Generation, a Market Participant shall take no actions to establish a Demand Response Baseline that results in a Demand Response Baseline that reduces the expected output levels of its generation absent demand reduction payments.

8. Real-Time Demand Reduction Obligations

8.1 Real-Time Demand Reduction of Assets Without Generation

The Real-Time demand reduction amount of a Real-Time Demand Response Asset is equal to the difference between its Demand Response Baseline adjusted pursuant to Section III.8A.4 and the asset's Real-Time metered demand, during the intervals that the Real-Time Demand Response Asset was scheduled Day-Ahead by the ISO to reduce demand or was otherwise eligible to receive payment for a demand reduction in Real-Time. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered demand is greater than its adjusted Demand Response Baseline.

8.2 Real-Time Demand Reduction of Assets With Generation

To the extent a generator is located behind the retail delivery point of an individual end-use customer facility that comprises a Real-Time Demand Response Asset, the metered output of the generator in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline. The Real-Time demand reduction amount achieved by the individual end-use customer facility that comprises a Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval minus the sum of the metered demand measured at the retail delivery point and the output of all of the generators located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of all of the generators is greater than its adjusted Demand Response Baseline.

If a Real-Time Demand Response Asset is comprised of a Distributed Generation asset located behind the retail delivery point of an individual end-use customer facility, the interval metered output of the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be used to determine its Demand Response Baseline. The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be equal to the asset's incremental output in each five-minute interval relative to its Demand Response Baseline in the same intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered output is less than its Demand Response Baseline.

8.2.1 Real-Time Demand Reduction of Assets With Generation But With No Other Real-Time Demand Response Asset at that Location

For a Real-Time Demand Response Asset located at a retail delivery point with no other Real-Time Demand Response Assets at or behind the same retail delivery point, the metered output of any Real-Time Emergency Generation Assets in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline.

The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval, calculated pursuant to Section III.8A.4.4, minus the sum of the metered demand measured at the retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of any Real-Time Emergency Generation Assets is greater than its adjusted Demand Response Baseline.

8.3 Treatment of Net Supply

If the metered amount measured at the retail delivery point reflects net energy supply during intervals in which Real-Time Demand Response Assets and/or Real-Time Emergency Generation Assets behind the retail delivery point had positive Real-Time demand reductions, then the amount of net energy supplied in an interval with a positive Real-Time demand reduction shall be subtracted from the Real-Time demand reduction amount in the same interval of each Real-Time Demand Response Asset and/or Real-Time Emergency Generation Asset behind that retail delivery point on a *pro rata* basis. The adjustment for net energy supply shall not result in a negative Real-Time demand reduction amount.

8.4 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Real-Time Demand Response Asset is equal to its Real-Time demand reduction amount adjusted for net supply (limited to 200% of the associated Demand Reduction Offer amount) multiplied by one plus the percent average avoided peak distribution losses.

9. Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Real-Time Demand Response Asset will be paid for its Day-Ahead Demand – Reduction Obligation multiplied by the Day-Ahead LMP for the Load Zone within which the Real-Time Demand Response Asset is located.

9.2 Real-Time Settlement

9.2.1. Real-Time Demand Response Assets with Cleared Demand Reduction Offers

A Market Participant with a Real-Time Demand Response Asset will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the final hourly Real-Time LMP for the Load Zone within which the Real-Time Demand Response Asset is located. The payment for the amount by which the Real-Time Demand Reduction Obligation exceeds the Day-Ahead Demand Reduction Obligation in an hour shall be set to zero if the provisional Real-Time LMP for that hour is less than the Demand Reduction Threshold Price.

A Market Participant will not be charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E1.5.1.

9.2.2. Real-Time Demand Response Assets without Cleared Demand Reduction Offers

If the Demand Reduction Offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which the Real-Time Demand Response Asset is located, the Market Participant will be paid the final hourly Real-Time LMP multiplied by its Real-Time Demand Reduction Obligation.

A Market Participant will not be charged pursuant to Section III.E1.9.2.2 if:

(a) a Demand Reduction Offer does not clear Day-Ahead pursuant to Section III.E1.4, and;

(b) the Real-Time Demand Response Asset produces a negative Real-Time demand reduction amount.

A Market Participant will not be paid for a Real-Time Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E1.5.1.

9.3 Cost Allocation

Payments and charges pursuant to this section will be allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes or incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

10. Average Distribution Losses

For purposes of Section III.E1, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

SECTION III

MARKET RULE 1

APPENDIX E2

DEMAND RESPONSE

Appendix E2 applies to Capacity Commitment Periods commencing on or after June 1, 2017.

APPENDIX E2

DEMAND RESPONSE

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Appendix E2 applies to Capacity Commitment Periods commencing on or after June 1, 2017.

APPENDIX E2

DEMAND RESPONSE

Appendix E2 applies to Capacity Commitment Periods commencing on or after June 1, 2017.

1. Demand Response Registration

1.1 Demand Response Resource Registration

A Market Participant may register a Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis and providing Operating Reserve subject to the following conditions:

(a) each Demand Response Resource must be a single Demand Response Asset or an aggregation of Demand Response Assets located within the same Dispatch Zone and Reserve Zone;

(b) each Demand Response Resource must be able to produce at least 100 kW of demand reduction; ~~and~~

(c) the Market Participant must comply with ISO required auditing and testing requirements; and

(d) the Market Participant must indicate whether it intends to maintain CLAIM10 or CLAIM30 capability for the Demand Response Resource.

A Market Participant may not register a Real-Time Emergency Generation Resource, an On-Peak Demand Resource, a Seasonal Peak Demand Resource or a Dispatchable Asset Related Demand to participate as a Demand Response Resource in the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant may not register a~~n existing~~ Generator Asset as a Demand Response Asset for the purpose of submitting Demand Reduction Offers. A Market Participant may not register a Demand Response Asset at the same Retail Delivery Point as an existing Generator Asset, and may not register a Generator Asset at the same Retail Delivery Point as an existing Demand Response Asset; provided that this provision shall not apply if the Generator Asset is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

1.2 Demand Response Capacity Resource Registration

A Market Participant may register a Demand Response Capacity Resource subject to the following conditions:

(a) each Demand Response Capacity Resource must have mapped to it at least one Demand Response Resource within the same Dispatch Zone in order to comply with the energy market offer requirements in Section III.13.6.1.5; and

(b) a Demand Response Resource cannot be mapped to a Demand Response Capacity Resource, or maintain the mapping to a Demand Response Capacity Resource, if the Demand Response Resource violates the mapping provisions in Section III.E2.1.4(c).

1.3 Demand Response Asset Registration

A Market Participant may register a Demand Response Asset subject to the following conditions:

(a) Unless it meets the conditions for aggregation in sub-section (b) below, a Demand Response Asset must have a defined, single Retail Delivery Point and be registered at a single Node. ~~For each Demand Response Aset capable of delivering Net Supply, a single Net Supply Generator Asset may be registered at the same Node as the Demand Response Asset unless the asset meets the conditions for aggregation in sub-section (b) below.~~

(b) A Demand Response Asset may be the aggregate demand reduction capability~~consumption~~ of multiple end-use customers from multiple delivery points within a single Dispatch Zone and Reserve Zone if (i) the demand reduction from each Retail Delivery Point in the aggregation is less than 10 kW, and (ii) the demand at the multiple Retail Delivery Points satisfy the criteria for a homogenous population. A Demand Response Asset that meets these conditions for aggregation must be registered ~~at the Dispatch Zone~~ at a single Dispatch Zone and Reserve Zone rather than at a single ~~the~~ Node. ~~For each Demand Response Asset capable of delivering Net Supply that meets the conditions for aggregation as described in this sub-section, a single Net Supply Generator Asset may be registered at the same Dispatch Zone as the Demand Response Asset,~~

(c) No more than one Demand Response Asset may be located at a single Retail Delivery Point.

(d) Each Demand Response Asset must be mapped to a Demand Response Resource.

(e) Each Demand Response Asset must be able to produce at least 10 kW of demand reduction.

(f) A Demand Response Asset with a registered Maximum Interruptible Capacity equal to or greater than 5 MW from the same Retail Delivery Point must be registered as a single Demand Response Resource at a Node. ~~A Demand Response Asset capable of delivering Net Supply where the sum of its Maximum Interruptible Capacity and Maximum Net Supply from the same Retail Delivery Point is equal to or greater than 5 MW must register as a single Demand Response Resource at a Node, and may register a single Net Supply Generator Asset at the same Node. In the event the Demand Response Asset and associated Net Supply Generator Asset have participated in a seasonal audit,~~ ~~t~~The evaluation of whether a Demand Response Asset's Maximum Interruptible Capacity ~~or the sum of the Maximum Interruptible Capacity and Net Supply~~ is equal to or greater than 5 MW shall account for the most recent seasonal audit results for the assets.

(g) The metering and communication equipment associated with each Demand Response Asset must meet the requirements in Section III.E2.2.

During the registration process, Market Participants must submit the following for each Demand Response Asset:

(a) Maximum Interruptible Capacity;

(b) Maximum Load;

(c) Maximum Generation, for Demand Response Assets that are comprised of Distributed Generation;

(d) ~~For any Net Supply Generator Asset associated with a Demand Response Asset, the~~ For a Demand Response Asset capable of producing Net Supply, the Maximum Net Supply permitted under the asset's interconnection agreement; and

(e) ~~retail~~ Retail account number and meter number for the end-use customer.

1.4 Restrictions on Demand Response Resource Registration

A Market Participant may not register and must retire if previously registered a Demand Response Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

(c) The Maximum Interruptible Capacity adjusted for the Audited Demand Reduction of each Demand Response Resource registered by a Market Participant within a single Dispatch Zone and Reserve Zone must be at least 1 MW before the Market Participant registers a new Demand Response Resource within that same Dispatch Zone and Reserve Zone. This restriction shall not apply if either:

(i) all Demand Response Assets registered by the Market Participant in the Dispatch Zone and Reserve Zone are mapped to a Demand Response Resource mapped to a Demand Response Capacity Resource and the Market Participant wants to register a Demand Response Resource that is not mapped to a Demand Response Capacity Resource; or

(ii) all Demand Response Assets registered by the Market Participant in the Dispatch Zone and Reserve Zone are mapped to a Demand Response Resource not mapped to a Demand Response Capacity Resource and the Market Participant wants to register a Demand Response Resource that is mapped to a Demand Response Capacity Resource.

(d) In the event the Audited Demand Reductions of two or more Demand Response Resources registered by a Market Participant within a single Dispatch Zone and Reserve Zone are less than 1 MW following an audit, Demand Response Asset mapping for that Market Participant shall be adjusted if doing so decreases the number of Demand Response Resources within that Dispatch Zone and Reserve Zone.

1.5 Restrictions on Demand Response Asset Mapping

Demand Response Assets may be un-mapped from a Demand Response Resource for re-mapping to another Demand Response Resource, or un-mapped without re-mapping, subject to the following conditions:

(a) A Demand Response Asset cannot be unmapped from a Demand Response Resource that is mapped to a Demand Response Capacity Resource if, following the un-mapping, the sum of the demand reductions of the remaining Demand Response Assets that are associated with the Demand Response Capacity Resource, as reflected in the most recent seasonal audit for that resource, would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

(b) When a Demand Response Asset can be mapped to more than one Demand Response Resource that is mapped to a Demand Response -Capacity Resource, a Demand Response

Asset shall be mapped to a Demand Response Resource associated with a Demand Response Capacity Resource whose demand reduction capability is less than~~t~~ the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period before being mapped to a Demand Response Resource associated with a non-commercial Demand Response Capacity Resource or non-commercial increment of a Demand Response Capacity Resource.

(c) A Demand Response Asset may be re-mapped to another Demand Response Resource only if the Audited Full Reduction Time of the asset's new Demand Response Resource, adjusted for the Audited Demand Reduction of the asset's current Demand Response Resource, is equal to or greater than the Audited Full Reduction Time of the Demand Response Resource from which the Demand Response Asset is being un-mapped.

(d) If a Demand Response Asset is re-mapped to a Demand Response Resource, and the Audited Full Reduction Time of the Demand Response Resource to which the asset is being mapped, adjusted for the Audited Demand Reduction of the Demand Response Resource from which the asset is being mapped, is less than the Audited Full Reduction Time of the Demand Response Resource from which the asset is being mapped, the Demand Response Asset audit value will be set to zero.

2. Metering and Communication

2.1 Revenue Quality Interval Metering ~~and Telemetry Requirements~~

The metered demand used for settlement purposes of each individual end-use customer facility that comprises a Demand Response Asset must be measured using interval meters located at the individual end-use customer's Retail Delivery Point and shall be reported to the ISO at an interval of five minutes. Metered demand data submitted to the ISO shall not include average avoided peak distribution losses.~~ Each generator located behind an individual end-use customer's Retail Delivery Point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.~~

The interval meters required pursuant to Section III.E2.2.1 must meet the following requirements:

(a) The interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes~~ or less~~;

(b) ~~If t~~The interval meter ~~is the same meter used by the distribution company for billing purposes, the meter is~~ can be the same ~~a~~ revenue-quality meter ~~that is accurate within ± 0.5%~~ used by the distribution company for billing purposes; and

(c) If the interval meter is not the same revenue-quality meter used by the distribution company for billing purposes, the Market Participant must validate and provide documentation to the ISO that the difference between the values recorded by the Market Participant's meter in each interval and the value recorded by the distribution company's billing meter in the same interval is within ± 2.0%; provided that, if accurate interval data from the distribution company are not available, the Market Participant shall validate that the difference between the sum of the values recorded by the Market Participant's meter and the sum of the values recorded by the distribution company's billing meter over the same time period is within ± 2.0%; and further provided that the Market Participant specifies the meter manufacturer and model, and the accuracy for the following parameters:

i. current measurement;
ii. voltage measurement;
iii. A/D conversion; and
iv. calibration.

(d) The Market Participant shall provide documentation to the ISO of any inaccuracies found in distribution company meter data and of any communications with the distribution company to address the meter data inaccuracies.

~~(b) If the interval meter is not the same meter used by the distribution company for billing purposes, the interval meter is either a revenue-quality meter that is accurate within ± 0.5% or a non-revenue-quality meter with an overall accuracy of ± 2.0%. For each non-revenue-quality meter used, the Market Participant must, during the registration process, submit certification from the meter manufacturer that the interval meter being used meets the ± 2.0% accuracy threshold, and shall specify accuracy for the following parameters:~~

~~(c)~~

~~(d) current measurement;~~

~~(e) voltage measurement;~~

~~(f) A/D conversion; and~~

~~(g) calibration.~~

2.2 Communication/Telemetry

Market Participants must report in Real-Time to the ISO a single set of telemetry data for each individual end-use customer facility that comprises a Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of the Demand Response Asset as measured at the Retail Delivery Point, and shall be reported to the ISO every five minutes. For a Demand Response Resource to provide Ten Minute Spinning Reserve or Ten Minute Non-Spinning Reserve, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

The Market Participant must utilize a remote terminal unit for communicating telemetry and receiving D~~d~~ispatch I~~i~~nstructions~~ from the ISO~~.

~~Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facilities that comprise the Demand Response Asset on the electricity network in the New England Control Area.~~

~~For Demand Response Assets whose demand reductions are not achieved by Distributed Generation but where there is a generator located behind the Retail Delivery Point, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility that comprises the Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of all generation.~~

If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of telemetry data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

~~For Demand Response Assets whose demand reductions are achieved by Distributed Generation, Market Participants must submit a single set of interval meter data representing the metered demand of the end-~~

~~use facility that comprises the Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of Distributed Generation associated with the Demand Response Asset.~~

The telemetry measurement device used to measure the real-time demand and any Net Supply pursuant to Section III.E2.2.2 must have an overall accuracy of ± 2.0%. If the Market Participant is not using the meter used by the distribution company for billing purposes to obtain the real-time telemetry, then the Market Participant must specify the device manufacturer and model, and submit certification from the measurement device manufacturer that the device being used meets the ± 2.0% accuracy threshold, and shall specify the accuracy for the following parameters:

i. current measurement;
ii. voltage measurement;
iii. A/D conversion; and
iv. calibration.

2.3 ~~Meter~~ Testing of Meters and Telemetry Measurement Devices

All interval meters and telemetry measurement devices must be periodically tested and calibrated.

Market Participants must conduct periodic meter and telemetry data validation checks.

Market Participants must repair or replace meters or telemetry measurement devices that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters, telemetry measurement devices, and ~~meter~~ data communication systems.

2.4 Auditing

The ISO may, for Demand Response Resources, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset.

Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing and certifying the metering, data recording and telemetry measurement equipment of Demand Response Assets.

3. Day-Ahead Energy Market Demand Reduction Offers

Market Participants must submit a Demand Reduction Offer for each Demand Response Resource that meets the requirements of this section in order to be eligible for a payment for a demand reduction ~~payment~~.

The Market Participant's Demand Reduction Offer for a Demand Response Resource must satisfy the following conditions:

(a) Demand Reduction Offers must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the applicable Operating Day.

(b) The Market Participant can submit up to 10 monotonically increasing price/demand reduction amount pairs for each Operating Day. The demand reduction amount shall not include an adjustment for average avoided peak transmission and distribution losses.

(c) The minimum amount for each price/demand reduction amount pair of a Demand Reduction Offer is 100 kW.

(d) The sum of all price/demand reduction amount pairs for a Demand Reduction Offer cannot exceed the sum of the Maximum Interruptible Capacities of the resource's Demand Response Assets.

(e) The minimum Demand Reduction Offer price must be equal to or greater than the Demand Reduction Threshold Price in effect for the day the Demand Reduction Offer is submitted.

(f) The maximum Demand Reduction Offer price must be less than or equal to the Energy Offer Cap ~~$1000/MWh~~.

Market Participants may not Self-Schedule interruptions in the Day-Ahead Energy Market.

3.1 Required Demand Reduction Offer Parameters

The Market Participant shall provide the following hourly values in its Demand Reduction Offer. The Market Participant shall maintain up-to-date values for each of these parameters prior to and throughout the Operating Day:

(a) Available or Unavailable;

(b) Minimum Reduction (MW), and;

(c) Maximum Reduction (MW).

3.2 Optional Demand Reduction Offer Parameters

The Market Participant may also specify the following in its Demand Reduction Offer:

(a) Interruption Cost ($)

(b) Minimum Reduction Time (Hrs)

(c) Minimum Time Between Reductions (Hrs)

(d) Demand Response Resource Start-Up Time (Hrs)

(e) Demand Response Resource Notification Time (Hrs)

(f) Demand Response Resource Ramp Rate (MW/min)

(g) Offered CLAIM10 (MW)

(h) Offered CLAIM30 (MW)

4. Real-Time Energy Market Demand Reduction Offers

During the Re-Offer Period, Market Participants may submit revisions to the price or demand reduction amount parameters of a Demand Reduction Offer. Demand Response Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices.

Revisions to Demand Reduction Offers during the Re-Offer Period are subject to the following conditions that apply to Day-Ahead Demand Reduction Offers under Section III.E2.3: limitation to 10 monotonically increasing price/demand reduction amount pairs, minimum amount, maximum amount, minimum price and maximum price.

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for that Operating Day pursuant to Section III.E2.5 or modified during the Re-Offer Period.

No changes will be allowed to the Demand Reduction Offer after the close of the Re-Offer Period. Market Participants may not Self-Schedule interruptions in the Real-Time Energy Market.

5. Scheduling and Dispatching

The ISO shall schedule in the Day-Ahead Energy Market and ~~commit~~schedule and dispatch in the Real-Time Energy Market the Demand Response Resource ~~based on:~~

~~(a) least-cost, security-constrained dispatch and commitment~~ as specified in Section III.1.7.6(a).~~; and~~

~~(b) the Demand Reduction Offer for the Demand Response Resource, with demand reduction by average avoided peak distribution losses.~~

At the conclusion of the Day-Ahead Energy Market clearing, the ISO will provide Market Participants with Day-Ahead demand reduction schedules for Demand Response Resources reflecting demand reduction amounts that do not include average avoided peak transmission and distribution losses for each hour of the following Operating Day.

During the Operating Day, the ISO will issue Dispatch Instructions to the Market Participant specifying the expected demand reduction amount that does not include average avoided peak transmission and distribution losses from their Demand Response Resource and the Dispatch Rate.

A Market Participant must notify the ISO, as soon as practicable, of a facility or generator shutdown or equipment outage (including partial outages) that reduces the Demand Response Resource's ability to achieve the demand reduction reflected in the Demand Reduction Offer for an Operating Day. ~~Net Supply Generator Assets will be dispatched at the same Location as the Demand Response Resource with which they are associated.~~

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data 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 demand response exceeds the cost to load associated with compensating demand response.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th}\text{Ã—}\frac{FPI_c}{FPI_h}$$

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 resulting 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 preceding month in advance of the Demand Reduction Threshold Price's effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Demand Response Resources located anywhere within the New England Control Area.

7. Real-Time Demand Reduction Obligation

A Demand Response Resource's Real-Time Demand Reduction Obligation will be calculated for each dispatch interval in which the Demand Response Resource receives a Dispatch Instruction to reduce demand.

7.1 Real-Time Demand Reductions

The Real-Time demand reduction in a dispatch interval is the difference between the adjusted Demand Response Baseline, further adjusted for any metered output for a Real-Time Emergency Generation Asset located at the same Retail Delivery Point, and the metered demand for each Demand Response Asset associated with the Demand Response Resource.

If a Market Participant receives a Dispatch Instruction for a Demand Response Resource to reduce demand in a dispatch interval by zero MW, then in calculating the Real-Time Demand Reduction Obligation of the Demand Response Resource the Real-Time demand reductions of the Demand Response Assets comprising the resource shall be equal to zero for that dispatch interval.

7.2 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Demand Response Resource is the sum of the hourly integrated Real-Time demand reduction amounts of the Demand Response Assets comprising the Demand Response Resource, multiplied by one plus the percent average avoided peak distribution losses, except that any Net Supply produced by the Demand Response Assets comprising the Demand Response Resource will not be adjusted by average avoided peak distribution losses~~In calculating the Real-Time Demand Reduction Obligation of a Demand Response Resource, the Real-Time demand reduction amounts of the Demand Response Assets comprising the resource shall be as specified in Section III.E2.7.3 below~~.

If a Market Participant fails to comply with the metering and communication requirements in Section III.E2.2 for a Demand Response Resource for any period of time, then the Real-Time Demand Reduction Obligation shall be zero for that period of time.

~~7.3 Treatment of Net Supply~~

~~If a Demand Response Asset's metered demand represents Net Supply, the Demand Response Asset's metered demand in the interval will be set equal to zero and that value will be used in establishing the Real-Time Demand Reduction Obligation.~~

8. Demand Response Resource Baseline

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8B prior to submitting a Demand Reduction Offer for a Demand Response Resource, and must comply with the requirements for maintaining and resetting the Demand Response Baseline as set forth in Section III.8B.

A Market Participant shall not take actions to create or maintain a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers in the absence of demand reduction payments.

9. Energy Market Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Demand Response Resource will be paid for its Day-Ahead Demand Reduction Obligation multiplied by the Day-Ahead LMP for the Dispatch Zone or Node at which the resource is registered.

9.2 Real-Time Settlement

A Market Participant with a Demand Response Resource will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the hourly Real-Time LMP for the Dispatch Zone or Node at which the resource is registered.

9.3 Cost Allocation

Charges or payments resulting from Real-Time demand reductions produced by Demand Response Resources or Real-Time Emergency Generation Resources shall be allocated on an hourly basis proportionally to Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

9.4 NCPC Credits and Charges

A Market Participant with a Demand Response Resource is eligible for NCPC credits if the resource is following Dispatch Instructions. A Market Participant with a Demand Response Resource is ineligible for NCPC credits and may be assessed NCPC charges if the resource is not operating within the acceptable dispatch tolerance. A resource is not operating within the acceptable dispatch tolerance if in any five-minute interval for an hour the resource is not operating within 10% above or below the resource's Dispatch Instruction, except that a Market Participant with a resource that is not operating within the acceptable dispatch tolerance will not be assessed NCPC charges if during the entire hour the resource operates within 5% above or below the resource's Dispatch Instruction.

10. Average Avoided Peak Distribution Losses

For purposes of Section III.E2, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool	))))	**Docket No. ER15-____-000**

TESTIMONY OF HENRY Y. YOSHIMURA

I. IDENTIFICATION OF WITNESS

Q: Please state your name, title, and business address.

A: My name is Henry Y. Yoshimura. I am the Director of Demand Resource Strategy for ISO New England Inc. (the "ISO"), One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: Please summarize your job responsibilities at the ISO.

A: I joined the ISO in 2002. In my current position, I am responsible for the development of demand resource initiatives for the New England wholesale electricity market and I assist ISO business units in implementing these initiatives.[1] I manage the ISO's Demand Resource Strategy Department to develop programs and market designs that integrate demand resources into the wholesale electricity markets, work with the ISO's Market Design group under the direction of Mr. Mark Karl, the Vice President of Market Development, and

[1] Capitalized terms used but not defined in this testimony are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 ("Tariff"), the Second Restated New England Power Pool Agreement, and the Participants Agreement.

work with external and internal stakeholder groups (e.g., Market Participants, New England Power Pool ("NEPOOL") Participants, state and Federal regulators, and the ISO's Market and System Operations, Planning, Settlements and IT Departments) to successfully implement such programs and market designs. I help integrate the ISO's demand resource initiatives into the wholesale capacity, energy, and ancillary service markets and into the regional system planning process to ensure efficient market design and consistent planning assumptions.

While at the ISO, I have served on the Board of Directors of the Demand Response Coordinating Committee and the Board of Directors of its successor organization, the Association for Demand Response and Smart Grid ("ADS"). ADS is a nonprofit organization consisting of policymakers, utilities, system operators, technology companies, consumers, and other stakeholders involved in the demand response and smart grid space. ADS facilitates the exchange of ideas, information, and expertise to help its members advance the deployment of demand response and smart grid.

I also serve as the Chair of the Demand Resources Working Group, which is a standing working group of the NEPOOL Markets Committee (the "Markets Committee") that reviews proposed changes to the market rules and manuals pertaining to demand resources as directed by the Markets Committee. The Demand Resources Working Group also provides a forum for stakeholders and the ISO to exchange ideas and information on topics such as: demand resource program implementation, business process improvements, marketing activities, administrative or operational problems and issues relating to the participation of demand resources in the wholesale electricity markets, ISO filings with the Commission concerning demand resources, and the results of analyses concerning demand resource performance.

I have appeared before the Federal Energy Regulatory Commission ("Commission") on behalf of the ISO on several occasions addressing demand response in organized electricity markets. Specifically, I appeared before the Commission in technical conferences on Demand Response in Organized Electric Markets held on April 23, 2007 in Docket No. AD07-11-000 and May 21, 2008 in Docket No. AD08-8-000, and concerning the National Action Plan on Demand Response held on November 19-20, 2009 in Docket No. AD09-10-000. I have sponsored testimony on demand response topics on behalf of the ISO many times.

Q: Please summarize your experience and qualifications prior to joining the ISO.

A: Before joining the ISO, I spent approximately two years in Jakarta, Indonesia with the Institute of International Education as the Chief of Party of a USAID-sponsored project in which I led and mentored a group of Indonesian staff to advise and assist the Government of Indonesia to restructure the Indonesian electricity sector and set up appropriate regulatory institutions. Before my assignment in Indonesia in 2000, I was a Senior Consultant of Economics and

Public Policy for XENERGY Consulting, Inc., where I managed a variety of projects related to electric industry restructuring in the United States. Before joining XENERGY in 1997, I was a Senior Consultant with La Capra Associates, a Boston-based consulting firm specializing in utility regulatory matters. While with La Capra, I helped several electric and gas utilities evaluate the cost-effectiveness of demand-side management options for inclusion in their integrated resource plans. I also advised the Massachusetts Division of Energy Resources ("DOER") in a series of proceedings including the Massachusetts Department of Public Utilities ("DPU") rulemaking concerning electric industry restructuring and assisted the DOER in settlement negotiations with Massachusetts Electric Company ("MECo") concerning the structure of MECo's restructuring plan, including the structure of the Standard Offer bidding process. Before joining La Capra Associates in 1992, I served on the staff of the DPU for about ten years and held several positions including Senior Economist, Assistant Director of the Electric Power Division, and Director of the Electric Power Division. As Director of the DPU's Electric Power Division, I managed staff working in the areas of utility cost of service and rate design, integrated resource planning, and demand-side management. I participated in the development and implementation of numerous regulatory policies such as marginal cost-based rate design, cost recovery standards for utility generation, competitive bidding regulations for non-utility generation, integrated resource management, and the incorporation of environmental externalities in utility integrated resource planning.

I have bachelor and graduate degrees in economics from the University of Montana. Including my work in graduate school, which was in the energy field, I have about 30 years of domestic and international experience as an economist and public policy expert in the electric power industry.

II. PURPOSE, BACKGROUND, AND SCOPE OF DIRECT TESTIMONY

Q: What is the purpose of this testimony?

A: The purpose of this testimony is to explain a number of market rule changes that are intended to support the ISO's efforts to fully integrate demand response into the New England wholesale electricity markets. By way of background, in response to the Commission's Order No. 745, Demand Response Compensation in Organized Wholesale Energy Markets,[2] the ISO proposed, and the Commission accepted, two sets of Tariff revisions to implement price-responsive demand in New England's wholesale energy market.[3] The two sets of changes provide for a two step implementation of price-responsive demand: a transition period, which largely continued the use of existing demand response programs, leading up to the full integration of demand response into the wholesale energy market starting on June 1, 2017. Additional changes were then filed to conform the Forward Capacity Market rules to the transition period rules and the fully integrated rules.[4]

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[2] *FERC*, Demand Response Compensation in Organized Wholesale Energy Markets, Order 745, Docket No. RM10-17-000 (March 15, 2011), http://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

[3] *ISO New England Inc.*, Order No. 745 Compliance Filing, Docket No. ER11-4336-000 (August 19, 2011); http://www.iso-ne.com/regulatory/ferc/filings/2011/aug/er11_4336_000_prd_filing.pdf

[4] Section I.A of the transmittal letter for this filing provides an overview of the ISO's price-responsive demand filings, with citations to the filings and orders.

The changes being proposed today further support the goal of fully integrating price-responsive demand into the wholesale electricity markets. Of primary significance, the proposed changes will enable Demand Response Resources to provide Operating Reserve and to participate in the Forward Reserve Market. The ISO is committed to enabling Demand Response Resources to provide Operating Reserve coincident with the full integration of Demand Response Resources into the energy markets.[5] The fundamental market design for the way in which Demand Response Resources would provide Operating Reserve and participate in the Forward Reserve Market was discussed in detail in a whitepaper dated September 26, 2013.[6]

In addition, the ISO is proposing a series of conforming changes to the market rules to support the integration of demand response into the wholesale energy market. Thus, while the existing version of Appendix E2 contains the market rules for the full integration of price-responsive demand into the energy market, a number of supplementary changes must be made to the main body of energy market rules in Sections III.1 through III.7 of Market Rule 1 to recognize the

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[5] The ISO committed to fully integrating Demand Response Resources into the Day-Ahead and Real-Time Energy Markets in response to Order No. 745. *See ISO New England Inc.*, Order No. 745 Compliance Filing, Docket Nos. ER11-4336-000 and ER11-4336-001 (August 19, 2011); http://www.iso-ne.com/regulatory/ferc/filings/2011/aug/er11_4336_000_prd_filing.pdf, and *ISO New England Inc.*, Order on Compliance Filing, 138 FERC ¶ 61,042 (January 19, 2012), accepted with conditions; http://www.iso-ne.com/regulatory/ferc/orders/2012/jan/er11-4336-000_1-19-12_ordr_on_ordr745.pdf.

[6] This whitepaper is available at: http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct22013/a5_iso_white_paper_drr_reserves_09_26_13.doc.

participation of Demand Response Resources in the energy market. Changes are also being made to the existing rules in Section III.8A and III.8B for calculating Demand Response Baselines throughout the Operating Day from which the availability of Operating Reserves from Demand Response Resources could be accurately quantified. Finally, changes are being proposed to the market rules that address the way in which Demand Response Resources with behind-the-meter generation that are able to produce Net Supply (i.e., inject energy into the electric grid) are accounted for and compensated.

Q: When is the ISO planning to fully integrate Demand Response Resources into the Operating Reserve structure and the Forward Reserve Market?

A: The ISO's current plan is to fully integrate Demand Response Resources into the energy market, the Operating Reserve structure, and the Forward Reserve Market on June 1, 2017 (i.e., the start of the 8th Capacity Commitment Period). The rules for the integration of Demand Response Resources into the energy market were developed and filed with the Commission in a series of filings in 2011, 2012, 2013, and 2014.[7] The Commission has accepted all of these rules. These rules are all currently effective under a structure that has Demand Response Resources serving as the vehicle for providing demand response in the energy market starting on June 1, 2017.

[7] As I noted above, Section I.A of the transmittal letter for this filing provides an overview of the ISO's price-responsive demand filings, with citations to the filings and orders.

Q: Does this mean that the market rule changes being proposed by the ISO today will become effective in June 2017?

A: No. The ISO is seeking to have the market rules filed herewith in place before February 2015, so that Market Participants have this information before participating in Forward Capacity Auction 9, scheduled for February 2015.

This same approach has been taken with prior sets of market rule changes that address the integration of price-responsive demand into the energy market, as well as conforming capacity market rule changes. Thus, the rules that address the full integration of Demand Response Resources in the energy market, which will begin on June 1, 2017, are in effect now in Appendix E2 of Market Rule 1. However, since, Demand Response Resources cannot participate in the energy market or begin providing capacity in the Forward Capacity Market until June 1, 2017 by definition,[8] those rules are effectively not operational until June 1, 2017. The same is true of the Demand Response Baseline rules (Section III.8B) and the rules that address the role of Demand Response Resources in the Forward Capacity Market. By having these rules in place now, Market Participants have a clear understanding of the rules and requirements that will apply for price-responsive demand once full integration is implemented in June 2017. This is particularly important for participants that are developing bids in the Forward Capacity Market for the auction to procure capacity for the June 1, 2018-May 31,

[8] Section I.2.2 defines Demand Response Resource as "an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017."

2019 Capacity Commitment Period, which is the period in which the ISO's proposed Forward Capacity Market Performance Incentives go into effect.[9] That auction will take place in February 2015.

Q: Does the integration of Demand Response Resources into the Operating Reserve structure and the Forward Reserve Market require a fundamental change in the structure of those markets?

A: No. The market rule changes proposed by the ISO today integrate Demand Response Resources into the existing Operating Reserve and Forward Reserve Market structures; the market rule changes proposed today do *not* change the fundamental structure of the existing markets.

Q: Why is the ISO proposing to integrate Demand Response Resources into the Operating Reserve and Forward Reserve Market structures?

A: Integrating Demand Response Resources into the existing Operating Reserve and Forward Reserve Market structures provides for the comparable treatment of Demand Response Resources along with all other Resources such as generators. By integrating all Resources into a common market structure, Market Participants supply product to the market under common product definitions, take on comparable obligations for the market within which they participate, and are paid the same price for the product they deliver. In such a market structure, the

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[9] *ISO New England Inc. and New England Power Pool*, Filings of Performance Incentives Market Rule Changes; Docket No. ER14-1050-000 (January 17, 2014); http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jan/er14_1050_000_1_17_14_pay_for_performace_part_1.pdf

dispatch of Resources to provide energy and the designation of Resources to provide Operating Reserve can be co-optimized to produce the most efficient market outcome. Expanding the potential for additional resources to supply comparable energy and Operating Reserve services in real time and on a forward basis can provide for a more reliable electric system and increases competition among the suppliers of those services.

Q: Does that mean that no special market rule provisions are needed to fully integrate Demand Response Resources into the energy markets, the Operating Reserve structure, and the Forward Reserve Market?

A: No. While the proposed market rules place Demand Response Resources and generation resources on equal footing, the proposed rules also include provisions unique to Demand Response Resources. To effectively integrate Demand Response Resources into the Operating Reserve and Forward Reserve Market rules, the market rules must recognize certain physical differences between Demand Response Resources and generation resources, in the same way that the market rules for the energy markets and Forward Capacity Markets have been modified to recognize these differences. For example, Demand Response Resources participate in the energy markets primarily by reducing demand as opposed to providing supply. Thus, the market rules for the provision of Operating Reserve must have language recognizing that real-time supply and demand can be balanced by reducing demand quickly (e.g., within 10 or 30 minutes) as well as increasing supply quickly. Additionally, rules are needed that define the computation of a Demand Response Baseline for use in the reserve designation process, which accurately projects and makes available in real time the potential for reduced demand for each future interval of an Operating Day. Also, some Demand Response Resources with behind-the-meter generation are able to periodically produce Net Supply (i.e., inject energy into the electric grid). Thus, the market rules for reserves must address the provision of reserve by a Demand Response Resource that can provide Net Supply.

To effectively integrate Demand Response Resources into existing market structures for Operating Reserve and the Forward Reserve Market, therefore, the proposed market rule changes include provisions recognizing the physical differences between Demand Response Resources and generation resources.

III. EXPLANATION OF THE PROPOSED MARKET RULE CHANGES

Q: Please summarize the proposed market rule changes.

A: The ISO proposes market rule changes in the following areas:

A. <u>Changes to the Modeling of Demand Response Assets that Can Produce Net Supply</u>.

The existing market rules contemplate that, under full integration of price-responsive demand, demand response that is capable of producing Net Supply must be modeled as two assets: a Demand Response Asset that reduces load from the electric grid, and a Net Supply Generator Asset that provides Net Supply to the electric grid. The ISO is now proposing a simplified common dispatch model, so that such a facility is modeled as a single Demand Response Asset, which then eliminates the need to create a separate Net Supply Generator Asset to model Net Supply in the energy market. This modeling change provides the platform that will allow reserves to be properly accounted for in a Demand Response Resource.

B. <u>Establishing Rules Regarding How Demand Response Resources Provide Real-Time Operating Reserve</u>.

The market design for Real-Time Operating Reserve is not being changed. However, to integrate Demand Response Resources into the existing co-optimized energy and Real-Time Operating Reserve structure, several market rule modifications are needed. These include giving Demand Response Resources the ability to submit reserve-related Demand Reduction Offer parameters, modifying the real-time reserve designation and settlement rules to include Demand Response Resources, applying revised Dispatch Zone/Reserve Zone registration requirements for Demand Response Resources, and including telemetry requirements for Demand Response Resources providing 10-minute Operating Reserve.

C. <u>Changing the Demand Response Baseline Adjustment Factor</u>.

Under the existing rules, a daily adjustment is made to the Demand Response Baseline to account for day-to-day differences in consumption that result from weather and other similar variations. Currently, this adjustment is applied after the Operating Day. However, if a Demand Response Resource is to provide reserves, the ISO must have an accurate accounting of the resource's availability throughout the Operating Day. To facilitate this, the ISO is proposing to modify the adjustment factor calculation so that it is applied throughout the Operating Day, with sufficient frequency to capture changes in consumption patterns over the course of the day. I explain below the analysis we performed to determine an appropriate approach to a more frequent, intra-day application of the Demand Response Baseline adjustment factor.

D. <u>Integrating Demand Response Resources into the Forward Reserve Market</u>.

The proposed rule changes also incorporate Demand Response Resources in the Forward Reserve Market, which will enable eligible Demand Response Resources to participate in the Forward Reserve Market and receive compensation for such participation. Similar to the market rule changes proposed by the ISO with respect to the energy market and Real-Time Operating Reserve, no changes to the basic design of the Forward Reserve Market are proposed. The rule changes instead integrate Demand Response Resources into the existing Forward Reserve Market structure.

E. <u>Auditing Demand Response Resources</u>.

The market rules are being modified to allow the ISO to audit and revise the CLAIM10 and CLAIM30 values of Demand Response Resources. As with other changes being proposed, these changes incorporate Demand Response Resources into the existing structure of the rules, rather than modify that structure. The proposed rule changes also specify operating parameter auditing requirements for Demand Response Resources, comparable to operating parameter auditing requirements for generators, and make other relatively minor changes to the Demand Response Resource capacity market auditing rules.

F. <u>Implementing Related Market Rule Changes</u>.

The ISO proposes to integrate recent Demand Response Baseline changes that were made during the transition period into the rules applicable to the full integration of demand response into the wholesale markets. These changes relate to the establishment of baselines for Demand Response Assets experiencing a scheduled or a forced curtailment, the conditions upon which baselines may be reset, and the constraints on the adjusted baseline of Demand Response Assets capable of producing Net Supply. The ISO also proposes modified metering requirements for behind-the-meter generators and for meters installed by Market Participants for their Demand Response Assets.

G. <u>Incorporating Other Minor Rule Changes</u>.

In developing the above-mentioned market rule changes to facilitate the participation of Demand Response Resources in the wholesale energy market and in the provision of Operating Reserve, the ISO conducted a comprehensive review of the Tariff. As a result of this review, the ISO proposes several conforming and/or non-substantive market rule changes to further clarify the Tariff.

A. MODELING DEMAND RESPONSE ASSETS THAT CAN PRODUCE NET SUPPLY

Q: Please explain the market design change with respect to the modeling of Demand Response Assets that can produce Net Supply.

A: The ISO is proposing to implement a "common dispatch model" for Demand Response Resources that are capable of producing Net Supply. Under the existing market rules for the full integration of price-responsive demand into the energy markets, a single facility that can reduce load from the electric grid and inject energy into the electric grid (i.e., provide Net Supply) as measured at its Retail Delivery Point is modeled as two assets: a Demand Response Asset that reduces load from the electric grid, and a Net Supply Generator Asset that provides Net Supply to the electric grid. Under the proposed common dispatch model, however, such a facility is modeled as a single Demand Response Asset, which then eliminates the need to create a separate Net Supply Generator Asset to model Net Supply in the energy market. This modeling change provides the platform that will allow reserves to be properly accounted for when provided by a Demand Response Resource. Under the common dispatch model, the *demand reduction* produced by a Demand Response Asset is the sum of (1) the *reduced load* from the electric grid and (2) any *Net Supply* provided to the electric grid as measured at the asset's Retail Delivery Point.

Q: Please explain the Net Supply Generator Asset model, which is in the present market design and rules.

A: The present market design represented in the current Tariff models a single customer facility capable of reducing load from the electric grid and providing Net Supply to the electric grid as two separate assets: a Demand Response Asset and a Net Supply Generator Asset, respectively. Demand Response Assets located in the same Dispatch Zone may be aggregated together to form a Demand Response Resource.[10] Under the present energy market model, a Demand Response Resource is the entity that participates in the energy markets for which Demand Reduction Offers are submitted by Market Participants. Although a Net Supply Generator Asset may be directly related to a specific Demand Response Asset that is part of a Demand Response Resource, the Net Supply Generator Asset is treated as a separate asset in the energy market model. Supply Offers associated with a Net Supply Generator Asset must be submitted into the energy markets separately and distinctly from Demand Reduction Offers of Demand Response Resources.

Q: What is the rationale for representing a single customer facility that is capable of reducing load from the electric grid and providing Net Supply to the electric grid as two separate assets?

[10] Large Demand Response Assets – those with 5 MW or more of capability to reduce load from and/or provide Net Supply to the electric grid – are required to participate in the energy markets individually as a separate and distinct Demand Response Resource.

A: Modeling a single customer facility that is capable of reducing load from the electric grid and providing Net Supply to the electric grid as two separate assets facilitates the separate and distinct measurement of load reductions from Net Supply. Separately measuring load reduction from Net Supply addresses the potential double-counting of Net Supply. For example, take a facility that normally consumes 10 MW while simultaneously producing 6 MW with its own behind-the-meter generation. In this situation, the meter reading at the Retail Delivery Point would be -4 MW (i.e., this facility is withdrawing 4 MW from the electric grid to meet its total power requirement),[11] so the facility's baseline would be -4 MW. If this facility responds to a Dispatch Instruction by reducing all 10 MW of power consumption while maintaining 6 MW of generation, the meter reading at the Retail Delivery Point would change to +6 MW. The difference between a -4 MW baseline and a meter reading of +6 MW is 10 MW. Therefore, this facility could receive a payment based on 10 MW of demand response provided.

However, if this facility also had a Generator Asset registered at the same Retail Delivery Point,[12] the Generator Asset could receive payment for 6 MW of power injected into the electric grid. This would result in a double-counting of the 6

[11] A common meter-reading convention is to show consumption as a negative number and production as a positive number.

[12] There are customer facilities in New England that have behind-the-meter generators separately participating in the wholesale markets as Generator Assets.

MW of Net Supply produced by the facility, resulting in an incorrect total settlement based on 16 MW, not 10 MW.

To prevent double-counting the 6 MW of Net Supply, the current Tariff limits demand reduction quantities produced by Demand Response Assets to the difference between the baseline and a meter reading of 0 MW. That is, meter readings for the purpose of measuring demand reductions produced by Demand Response Assets are not allowed to go positive (i.e., not permitted to include Net Supply). So, if the meter at the Retail Delivery Point of a Demand Response Asset shows +6 MW during dispatch, the meter reading for the purposes of quantifying the demand reduction would be capped at 0 MW. Thus, the demand response payment from the above example would be based on the difference between a -4 MW baseline and capped meter reading of 0 MW (i.e., the Demand Response Asset would receive payment for reducing 4 MW from the grid). The 6 MW of Net Supply that was also provided – as shown by the +6 MW meter reading during the period of dispatch – would be credited to a separate Net Supply Generator Asset registered at the same location, resulting in the correct total settlement based on 10 MW delivered to the electric grid.

The Net Supply Generator Asset approach also facilitates the correct accounting for average avoided peak distribution losses. Since reducing load on the electric grid tends to reduce losses on the distribution system, a facility that reduces load from the electric grid should be credited for average avoided peak distribution losses.[13] On the other hand, like any other generation produced on the electric grid, Net Supply produced by a facility should *not* be credited for average avoided peak distribution losses because this increased generation incurs losses between the point of production and the point of consumption. Therefore, if a facility is able to both reduce load from and provide Net Supply to the electric grid, the load reduction amount should be credited for average avoided peak distribution losses whereas the Net Supply amount should not be credited. By separating load reductions produced by Demand Response Assets from Net Supply produced by Net Supply Generator Assets, the application of average avoided peak distribution losses in settlement quantities is clear and straightforward.

Q: Why is the ISO proposing to replace the Net Supply Generator Asset model at this time?

A: The approach is administratively complex for Market Participants. For each facility capable of producing Net Supply, Market Participants must estimate load reduction separately from Net Supply and bid these quantities into the energy markets separately between its Demand Response Resources and Net Supply Generator Assets.

[13] Crediting load reductions for average avoided peak distribution losses was proposed by the ISO in response to Order No. 745. This practice was affirmed by the Commission in *ISO New England*, 138 FERC ¶ 61,042 (2012); *ISO New England*, 142 FERC ¶ 61,027 (2013) at PP 12, 52, 56-57; *ISO New England*, 144 FERC ¶ 61,140 (2013) at P 18; *ISO New England*, 146 FERC ¶ 61,175 (2014) at PP 2, 8, 29.

In addition, the energy/reserve market structure into which Demand Response Resources will be integrated assumes that each asset in the market model is independent and can be dispatched in accordance with its individual energy offer parameters to meet both economic and security objectives. However, a customer facility that normally consumes some amount of energy from the electric grid and is capable of providing Net Supply must first reduce its load from the grid before it could provide Net Supply. For these facilities, it is physically impossible to provide Net Supply before load reduction. This means that there is an inter-temporal dependency between the Demand Response Asset and a Net Supply Generator Asset located at the same facility. That is, the Demand Response Asset must be dispatched *before* the energy of the Net Supply Generator Asset becomes available.

The dependency between the Demand Response Asset and the Net Supply Generator Asset at a facility could result in over-estimating the amount of Operating Reserve that could be provided by the facility. Expanding from the previous example – i.e., a facility that normally consumes 10 MW, produces 6 MW, and draws 4 MW from the grid – assume that the Demand Response Asset at this facility offered to provide 4 MW of Thirty Minute Operating Reserve ("TMOR"), and the Net Supply Generator Asset offered to provide 6 MW of TMOR. With each asset treated independently, the facility could be designated to provide a total of 10 MW of TMOR. However, if the facility needs 30 minutes to reduce power consumption from 10 MW to 5 MW, and another 30 minutes to further reduce its consumption to 0 MW, the most TMOR that this facility could provide is 5 MW – i.e., 4 MW from the Demand Response Asset and 1 MW from the Net Supply Generator Asset – not 10 MW.[14] By modeling this facility as two separate and independent assets (as would be the case under the Net Supply Generator Asset model), the amount of Operating Reserve provided by the facility could be over-estimated.

Q: What is the ISO planning to do to address the shortcomings of the Net Supply Generator Asset model?

A: To address the shortcomings of the Net Supply Generator Asset model, the ISO developed the "common dispatch model." Rather than representing a customer facility that is capable of reducing its load from and delivering Net Supply to the electric grid as two separate assets, the common dispatch model represents this facility as a single Demand Response Asset that is part of a Demand Response Resource. The common dispatch model eliminates the need to create a separate Net Supply Generator Asset to account for the Net Supply that a facility with behind-the-meter generation could produce. This greatly simplifies Market Participant administration of energy market offers for such facilities and allows for the correct accounting of Operating Reserve that a facility capable of Net Supply can provide to the grid.

[14] This facility could provide 10 MW of TMOR – 4 MW from the Demand Response Asset and 6 MW from the Net Supply Generator Asset – only if the facility could reduce all 10 MW of power consumption within 30 minutes.

Q: Please illustrate how the common dispatch model works, and how it addresses the shortcomings of the Net Supply Generator Asset model.

A: Returning to the previous example of a facility that normally consumes 10 MW, produces 6 MW, and draws 4 MW from the grid, a single Demand Reduction Offer related to this facility would be entered under the common dispatch model. Assuming that the capacity of the behind-the-meter generator of this facility is 6 MW and the facility is willing and able to reduce all 10 MW of power consumption, the Market Participant for this facility could submit a single Demand Reduction Offer covering the entire 10 MW – consisting of 4 MW of load reduction from the grid and 6 MW of Net Supply – that this facility could produce.

The common dispatch model eliminates the potential for over-estimating the amount of Operating Reserve that a facility can provide. I previously explained how a facility that normally consumes 10 MW, produces 6 MW, and draws 4 MW from the grid, could be counted to provide 10 MW of TMOR under the Net Supply Generator Asset model even if the facility needed more than 30 minutes to reduce power consumption sufficiently to produce all 10 MW. Under the common dispatch model, however, the performance of this facility is evaluated as a single asset. So if this facility can reduce 5 MW of power consumption within 30 minutes – showing as 4 MW of load reduction from the grid and 1 MW of Net Supply as measured from its Retail Delivery Point – it would only be allowed to provide 5 MW of TMOR. Thus, the common dispatch model addresses the danger of over-estimating the amount of reserves that a facility that can produce Net Supply could provide.

Q: You previously stated that the Net Supply Generator Asset model avoided the potential for double-counting Net Supply and facilitated the correct application of average avoided peak distribution losses in settlement quantities – i.e., that average avoided peak distribution losses would be applied only to load reductions from the grid and not to Net Supply. How does the common dispatch model achieve these objectives?

A: With respect to the potential for double-counting Net Supply, the common dispatch model avoids double counting by simply measuring the performance of a Demand Response Asset as the difference between the asset's adjusted Demand Response Baseline and its metered demand during a period of dispatch. Consider the previous example of a Demand Response Asset that normally consumes 10 MW, produces 6 MW, and draws 4 MW from the grid, whereby the adjusted Demand Response Baseline of the asset is -4 MW. If the asset reduces all 10 MW of consumption in response to dispatch, its metered demand would become +6 MW, reflecting 6 MW of Net Supply. Under the common dispatch model, the demand reduction quantity of this asset would be the difference between the baseline of -4 MW and the metered demand of +6 MW, or 10 MW, which is the correct demand reduction quantity. Had we double-counted Net Supply, the demand reduction quantity would have been 16 MW.

With respect to the correct accounting for average avoided peak distribution losses, as explained previously, reductions in load at the Retail Delivery Points of Demand Response Assets comprising a Demand Response Resource will result in the reduction of distribution losses. On the other hand, Net Supply produced by Demand Response Assets comprising a Demand Response Resource does not result in a reduction in distribution losses. Accordingly, the settlement of load reductions measured at a Retail Delivery Point should be increased by the average avoided peak distribution losses whereas Net Supply should not be increased. Under the common dispatch model, however, any Net Supply produced by Demand Response Assets is now credited to the performance of the Demand Response Resource to which it is associated along with any load reductions produced. In order to correctly apply average avoided peak distribution losses to the performance of a Demand Response Resource, Net Supply and load reduction amounts need to be quantified separately in the settlement process.

In real time, the amount of Net Supply produced by a Demand Response Asset is clear. Positive meter readings indicate power being injected into the electric grid (i.e., Net Supply is being produced), whereas negative meter readings indicate power being consumed from the electric grid. In the settlement process, therefore, the ISO proposes to increase load reductions delivered in real time at a Retail Delivery Point by one plus the average avoided peak distribution losses, whereas Net Supply delivered in Real-Time would not be increased.

Prior to Real-Time, however, it is not clear what portion of a Market Participant's Demand Reduction Offer, particularly its Day-Ahead Demand Reduction Offer, is associated with the provision of Net Supply. Accordingly, an assumption regarding the application of distribution losses to a cleared Day-Ahead Demand Reduction Offer must be made. Any such assumption employed should allow Market Participants to mitigate the potential difference between the assumed level of Net Supply in a Day-Ahead Demand Reduction Offer and the actual level of Net Supply produced in Real-Time so as to minimize deviations between the quantities cleared Day-Ahead versus those expected to be delivered in Real-Time. To address this issue, the ISO proposes that the settlement process assume that all cleared Day-Ahead Demand Reduction Offers are associated with load reductions only (i.e., no Net Supply would be assumed in a cleared Day-Ahead Demand Reduction Offer).[15] Accordingly, the entire cleared Day-Ahead Demand Reduction Offer would be multiplied by one plus average avoided peak distribution losses in the settlement process.

Q: How does the proposed approach allow a Market Participant to mitigate the potential difference between the assumed level of Net Supply in a Day-Ahead Demand Reduction Offer and the actual level of Net Supply produced in Real-Time so as to minimize deviations?

[15] This assumption is reflected in the defined term "Day-Ahead Demand Reduction Obligation" found in Section I.2.2.

A: To the extent a Market Participant expects that a portion of its Demand Response Resource would perform in Real-Time by providing Net Supply, the Market Participant can correspondingly reduce its Day-Ahead Demand Reduction Offer to reduce the potential deviation between the quantities cleared Day-Ahead versus those expected to be delivered in Real-Time. Presently, average avoided peak distribution losses are estimated to be 6.5 percent. Given that, the Market Participant can adjust its Day-Ahead Demand Reduction Offer for any Net Supply its Demand Response Resource is expected to produce in Real-Time. To minimize the deviation between Day-Ahead and Real-Time Demand Reduction Obligations, the Market Participant's Day-Ahead Demand Reduction Offer could include 1/1.065 MW or about 0.939 MW for each MW of Net Supply that a Demand Response Resource is expected to produce in Real-Time.

In addition, this approach has the benefit of being simple to administer, and is largely reflective of the way in which we anticipate that Demand Response Resources will function. We expect that the majority of demand reductions provided by Demand Response Resources will be in the form of load reductions measured at the Retail Delivery Point and not Net Supply.

Q: Are avoided distribution losses considered when determining the amount of reserves that a resource can provide in real time?

A: No. While reducing load at end-use customer facilities reduces losses on average as explained above, actual avoided losses will vary depending on specific system loading conditions, which are changing constantly. That is, actual avoided losses will vary from moment-to-moment and location-to-location and may be substantially greater or less than average losses. Given the variable nature of avoided losses and the difficulty in estimating them in real time, the present real-time reserve designation process for generators does not consider avoided losses. The ISO does not anticipate having the capability to estimate avoided distribution losses by time and location in the foreseeable future. The ISO is reluctant to rely upon avoided distribution losses to meet NERC reserve requirements given that such avoided losses may not materialize when a specific set of resources are dispatched in real time. Therefore, the ISO plans to continue the current practice of not considering potential avoided losses in the real-time reserve designation process.

Q: How are the proposed market rules impacted by changing from the Net Supply Generator Asset model to the common dispatch model?

A: Many provisions of the market rules are impacted by this change. To start with, the defined term "Demand Response Asset" is being changed to the following so as to credit any Net Supply to the Demand Response Asset:

> **Demand Response Asset** is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2. The demand reduction of a Demand Response Asset is the difference between the Demand Response Asset's actual demand measured at the Retail Delivery Point, ***which could reflect Net Supply***, at the time the Demand Response Resource to which the asset is

associated is dispatched by the ISO, and its adjusted Demand Response Baseline (emphasis added) – *see* Section I.2.2.

Further, replacing the Net Supply Generator Asset model with the common dispatch model is most noticeable in the proposed market rule changes in Section III.13.[16] In numerous locations in Section III.13, phrases like “the Demand Response Resource and associated Net Supply Generator Asset” are being changed to simply “the Demand Response Resource.” Because Demand Response Resources consist of one or more Demand Response Assets, and since the definition of Demand Response Asset is being modified to include any Net Supply, there is no need to define a separate Net Supply Generator Asset.[17] Similarly, where the terms “the Demand Reduction Offers and Supply Offers” are currently used to refer to energy market offers of Demand Response Resources and Net Supply Generator Assets, this phrase is being modified to simply “the Demand Reduction Offer” since any Net Supply produced will be credited to the performance of the Demand Response Resource. Further, any requirements specific to Net Supply Generator Assets are being eliminated.

Replacing the Net Supply Generator Asset model with the common dispatch model also impacts other sections of the Tariff including the defined terms (Section I.2.2), the Forward Capacity Market rules (Section III.13), the energy

[16] The affected sections include: Sections III.13.1.4.3, III.13.5.3.2.3, III.13.6.1.5.1, III.13.6.1.5.2, III.13.6.1.5.4.2, III.13.6.1.5.4.3.3.1, III.13.6.1.5.4.5, III.13.6.1.5.4.6, III.13.6.2.5.1, III.13.6.2.5.1.1, III.13.6.2.5.1.2, III.13.7.1.5.10.1, III.13.7.1.5.10.1.1, III.13.7.1.5.10.2, and III.13.7.2.5.4.1.

[17] The defined term Net Supply Generator Asset was deleted from Section I.2.2.

market rules for the full integration of price-responsive demand (Appendix E2), and the Demand Response Baseline rules (Sections III.8A and III.8B). The defined term "Maximum Interruptible Capacity" is being modified to include both the load reduction and Net Supply capability of a Demand Response Asset – *see* Section I.2.2. Since the Net Supply potential of a Demand Response Asset is now part of the asset's Maximum Interruptible Capacity, it is no longer necessary to add the Maximum Net Supply of a Demand Response Asset to its Maximum Interruptible Capacity to determine the asset's overall capability. Therefore, Sections III.8A.5.1, III.13.7.1.5.10.2(a)(ii), and III.E2.3 are being revised so that a Demand Response Asset's Maximum Net Supply is no longer added to its Maximum Interruptible Capacity to determine its overall capability. Similarly, the change in the definition of Maximum Interruptible Capacity simplifies Section III.E2.1.3(f).

Replacing the Net Supply Generator Asset model with the common dispatch model also affects Sections III.E2.1.3, III.E2.5, and III.E2.7.2 in Appendix E. For example, under the two asset model for Net Supply, the settlement quantity "Real-Time Demand Reduction Obligation" applies to only the load reduction amount measured at the Retail Delivery Points of the Demand Response Assets comprising a Demand Response Resource; any Net Supply produced at a Retail Delivery Point is credited to a separate Net Supply Generator Asset. Under the common dispatch model, Net Supply Generator Assets are being eliminated and any Net Supply produced is credited to a Demand Response Asset and ultimately to the Demand Response Resource to which the asset is associated. However, Net Supply should not be increased by average avoided peak distribution losses as previously discussed. Therefore, the calculation of the Real-Time Demand Reduction Obligation is being modified so that only the load reduction portion measured at the Retail Delivery Points is multiplied by one plus the average avoided peak distribution losses; to that amount, any Net Supply produced by the Demand Response Assets is then added (unadjusted for losses) to determine the Real-Time Demand Reduction Obligation of the Demand Response Resource.

Similarly, in the Operating Reserve rules (Section III.10), Section III.10.4.1 involves the computation of Forward Reserve Obligation Charge MW, which is a value used in the settlement of a Forward Reserve Resource. The Forward Reserve Obligation Charge MW is the lesser of the Forward Reserve Delivered MW or Real-Time Reserve Designation MW. The portion of Forward Reserve Delivered MW associated with load reductions (not including Net Supply) includes average avoided peak distribution losses. To facilitate an “apples-to-apples” comparison between Forward Reserve Delivered MW and Real-Time Reserve Designation MW in the determination of Forward Reserve Obligation Charge MW, the load reduction portion (and not the Net Supply portion) of Real-Time Reserve Designation MW must be increased by average avoided peak distribution losses in the settlement process.

Finally, Sections III.8B.1, III.8B.5 and III.E2.7.3 are affected by the replacement of the Net Supply Generator Asset model with the common dispatch model. To prevent double-counting of Net Supply under the Net Supply Generator Asset model, the metered demand of a Demand Response Asset is set to zero if Net Supply is produced. This adjustment is no longer needed under the common dispatch model.

B. ESTABLISHING RULES REGARDING HOW DEMAND RESPONSE RESOURCES PROVIDE REAL-TIME OPERATING RESERVE

Q: Please explain the market rule changes that will allow Demand Response Resources to provide Real-Time Operating Reserve.

A: As mentioned previously, the market rule changes proposed by the ISO integrate Demand Response Resources into the existing co-optimized energy and Real-Time Operating Reserve market structures. These rule changes are not intended to change the existing structure. To integrate Demand Response Resources into the co-optimized energy and Real-Time Operating Reserve structure several market rule modifications are needed to address issues unique to Demand Response Resources. These modifications include:

- Additional Reserve-Related Offer Parameters,
- Real-Time Reserve Designation and Settlement,
- Dispatch Zone/Reserve Zone Registration, and
- Telemetry Requirement for Demand Response Resources Providing 10-Minute Reserves.

i. Additional Reserve-Related Offer Parameters

Q: Please explain the market rule changes related to additional reserve-related offer parameters.

A: To provide Operating Reserve from an off-line state, a Generator Asset must have an Offered CLAIM10 and/or an Offered CLAIM30 value in its energy market offer. The Offered CLAIM10 value represents the amount of 10-minute reserve available from a Resource. The Offered CLAIM30 value represents the amount of 30-minute reserve available from a Resource. Under the existing market rules, in particular as reflected in the CLAIM10/30 rules in Section III.9.5.3, the Offered CLAIM10/30 values of a Resource are capped at values that reflect the Resource's performance during a CLAIM10/30 audit, which are adjusted over time based on the Resource's actual performance in response to dispatch. For a Demand Response Resource to provide 10- and/or 30-minute Operating Reserve from an undispatched state, the resource must also have an Offered CLAIM10 and/or an Offered CLAIM30 value in its Demand Reduction Offer. Therefore, the definitions of Offered CLAIM10 and Offered CLAIM30 in Section I.2.2, as well as the listing of offer parameters for Demand Response Resources in Section III.E.2.3, are being modified to allow the Market Participant of a Demand Response Resource to submit an Offered CLAIM10 and/or an Offered CLAIM30 value to represent the amount of 10-minute and/or 30-minute reserve that the Market Participant of an undispatched Demand Response Resource is willing to offer.

In addition, as part of the registration information maintained on Demand Response Resources, the Market Participant must indicate whether the Demand Response Resource will maintain CLAIM10 or CLAIM30 capability – *see* Section III.E2.1.1.

ii. Real-Time Reserve Designation and Settlement

Q: Please explain the market rule changes related to Real-Time reserve designation and settlement.

A: The manner in which Demand Response Resources will be designated to provide Real-Time Operating Reserve will be identical to the manner in which other Resources, such as Generator Assets, are presently designated to provide Real-Time Operating Reserve. Most of the market rule changes needed to effectuate the provision of Operating Reserve by Demand Response Resources involves the inclusion of "or Demand Response Resource" in numerous locations of the market rules where generators are mentioned, and "or demand reduction" in locations where generator output is mentioned. The defined terms for Operating Reserve products in Section I.2.2 (i.e., Ten-Minute Non-Spinning Reserve ("TMNSR"), Ten-Minute Spinning Reserve ("TMSR"), and Thirty-Minute Operating Reserve ("TMOR")) are each being modified to include Demand Response Resources as a type of Resource that can provide Operating Reserve. Sections III.10.1.1 and III.E2.1.1 are also being clarified so that Demand Response Resources are identified as a type of resource that can be designated to provide Operating Reserve. Also, since Demand Response Resources will be eligible to provide reserves, they will be eligible to help meet a locational reserve requirement. Therefore, Section III.9.2.2 on locational reserves is being modified to explicitly recognize Demand Response Resources in setting the locational reserve requirements.

In addition, to fully address real-time reserve designation and settlement for Demand Response Resources requires recognizing certain physical characteristics that distinguish Demand Response Resources from generation resources:

- Defining "Off-line" and "On-line" Demand Response Resources,
- Defining a Fast Start Demand Response Resource,
- Designating a Demand Response Resource to Provide TMSR, and
- Designating a Demand Response Resource to Provide TMNSR and TMOR.

Q: Please explain the market rule changes that define an "Off-line" and "On-line" Demand Response Resource.

A: The manner in which a Generator Asset is designated to provide Operating Reserve differs based on whether the generator is "off-line" or "on-line." A generator that provides reserves from an off-line state must establish, through an audit or demonstrated performance in response to dispatch, its ability to provide an amount of power within 10 or 30 minutes. A generator's demonstrated ability to provide off-line, 10-minute reserve is referred to as "CLAIM10" capability; its demonstrated ability to provide off-line, 30-minute reserve is referred to as "CLAIM30" capability. An on-line generator does not have to demonstrate its capability through a CLAIM10/30 audit to be eligible to provide reserves. The capability of an on-line generator is determined based on real-time telemetry, its Economic Maximum Limit, and its ramp rate.

Similarly, the market rules that allow Demand Response Resources to provide reserves must recognize its "off-line" or "on-line" state at the time it is being designated. However, the application of generator terminology to Demand Response Resources could be extremely confusing. For example, an "on-line" generator is connected to the electric grid and has been dispatched to generate power.[18] On the other hand, a Demand Response Resource is connected to the electric grid and is consuming power *before* it has been dispatched. So is a Demand Response Resource on-line or off-line in this instance?

To be clearer, the proposed market rules use somewhat different terminology for Demand Response Resources. A Demand Response Resource that has been "***dispatched***" to provide a portion or all of its demand reduction is similar to a generator that is "on-line." A Demand Response Resource that is "***not dispatched***" or ***"undispatched"*** (i.e., has not received a commitment or Dispatch Instruction[19]) is equivalent to a generator that is "off-line."

[18] An "off-line" generator is not connected to (i.e., not synchronized with) the electric grid.

[19] The defined term Dispatch Instruction was modified in the proposed rule to incorporate the dispatch of Demand Response Resources based upon its Demand Reduction Offer – see Section I.2.2.

Q: Please explain the market rule changes that define a Fast Start Demand Response Resource.

A: To provide Operating Reserve from an off-line state, a Generator Asset must meet the definition of a Fast Start Generator. A Fast Start Generator is a generating unit that the ISO may dispatch within the hour through electronic dispatch and that meets the following criteria: (i) minimum run time does not exceed one hour; (ii) minimum down time does not exceed one hour; (iii) time to start does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time. Similarly, a Demand Response Resource with similar "fast start" characteristics ought to be able to provide Operating Reserve from an undispatched state.

Accordingly, the ISO proposes a new defined term in Section I.2.2 – Fast Start Demand Response Resource – and is integrating this term into the appropriate sections of the Tariff, which allow Demand Response Resources to provide Operating Reserve from an undispatched state. The modified sections of the Tariff include Sections III.2.4; III.9.5.2; and III.9.7.2.

A Fast Start Demand Response Resource has similar requirements to a Fast Start Generator. Like a Fast Start Generator, a Fast Start Demand Response Resource must meet the following criteria:

- Minimum Reduction Time does not exceed one hour;
- Minimum Time Between Reductions does not exceed one hour;
- Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes;
- Has personnel available to respond to Dispatch Instructions or has automatic remote response capability;
- Is capable of receiving and acknowledging a Dispatch Instruction electronically; and
- Has satisfied its Minimum Time Between Reductions.

Q: Please explain the changes to the definitions that will allow Demand Response Resources to provide TMSR.

A: For a generator to provide Ten-Minute Spinning Reserve, the generator must already be "on-line" (i.e., it must be synchronized to the electric grid and eligible for dispatch). In contrast, a Demand Response Resource that is consuming energy from the electric grid is already synchronized to the grid even though it is not dispatched. Accordingly, the defined term for TMSR in Section I.2.2 is being modified to recognize that any Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO can potentially provide TMSR, with the exception of those with a constituent Demand Response Asset that has a generator whose output can be controlled located behind the Retail Delivery Point, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System.

Q: Why is a Demand Response Resource prohibited from providing TMSR if it has a constituent Demand Response Asset that has generator whose output

can be controlled located behind the Retail Delivery Point, with the noted exception for certain emergency generators?

A: By definition, an off-line generator is not synchronized to the electric grid and therefore cannot provide spinning reserve. Further, generating stations with multiple units behind a common metering point are similarly not allowed to provide TMSR given that the ISO cannot determine whether any individual unit behind the metering point is off-line and must be started and synchronized with the electric grid before it could provide service. Northeast Power Coordinating Council ("NPCC") standards provide that a Demand Response Resource that must start a behind-the-meter generator may not provide TMSR.[20] Like multi-unit generators behind a common metering point, the ISO cannot readily determine whether any behind-the-meter generators comprising part of a Demand Response Resource must be started in order to comply with a Dispatch Instruction. Accordingly, the market rules proposed by the ISO herein prohibit a Demand Response Resource with any controllable behind-the-meter generation (other than emergency generators that cannot operate electrically synchronized to the power grid[21]) from providing TMSR. However, Demand Response Resources with controllable behind-the-meter generation would be eligible to provide TMNSR and TMOR.

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[20] NPCC Directory #5, Section 5.15(b).

[21] This exception is appropriate because a Demand Response Asset with such an emergency generator must first disconnect from the power grid *before* turning on the emergency generator. The act of disconnecting the load of the asset from the power grid accomplishes the load reduction from the grid – the load reduction is not provided by the emergency generator.

Q: Please explain the changes to the definitions that will allow a Demand Response Resource to provide TMNSR and TMOR.

A: For a generator to provide Ten-Minute Non-Spinning Reserve or Thirty-Minute Operating Reserve, it must be able to convert its reserve capability into energy within ten or thirty minutes, respectively, from the request of the ISO. A generator converts reserve capability into energy by producing output. The defined terms for TMNSR and TMOR in Section I.2.2 are being modified to recognize that a Demand Response Resource provides TMNSR or TMOR by providing a demand reduction within ten or thirty minutes from the request of the ISO.

Q: What sections of the Tariff were modified to allow Demand Response Resources to be designated to provide TMSR, TMNSR, and TMOR in Real-Time as described above?

A: The sections of the Tariff that were modified to allow Demand Response Resources to be designated to provide TMSR, TMNSR, and TMOR in Real-Time include:

- Section III.1.7.19 on ramping capability is being updated to include parallel ramping requirements for Demand Response Resources (i.e., a Demand Response Resource must be able to change its demand reduction at the ramp rate specified in its Offer Data);
- Section III.2.7A on the calculation of Real-Time Reserve Clearing Prices is being updated to reflect that Demand Response Resources will provide Operating Reserve, with no changes to the clearing price calculation methodology;
- Section III.10.1.1 on Real-Time Reserve Designation is being updated to reflect that the designation must be determined for Demand Response

Resources providing Operating Reserve, again with no change to the current calculation methodology, and

- Section III.E2.1.1 on Demand Response Resource registration is being updated to reflect that the resource may be registered to provide reserves as well as to provide energy.

iii. Changes related to Dispatch Zone/Reserve Zone Registration

Q: Please explain the market rule changes related to Dispatch Zone/Reserve Zone Registration.

A: In contrast to Generator Assets, Demand Response Resources mostly consist of aggregations of individual Demand Response Assets located within the same Dispatch Zone.[22] However, the market for reserves varies by Reserve Zone, particularly in the Forward Reserve Market. Since the ISO proposes that Demand Response Resources be allowed to meet a Forward Reserve Obligation, Demand Response Assets that comprise a Demand Response Resource must be located in the same Reserve Zone.[23]

However, the current Dispatch Zones and Reserve Zones do not align in all cases given differences in the process for developing Dispatch Zones and Reserves Zones differ. That is, it is possible for a Dispatch Zone to span portions of more than one Reserve Zone. For example, the present Western Connecticut Dispatch Zone spans the Southwest Connecticut and Connecticut Reserve Zones. Without

[22] Like Generator Assets, large Demand Response Assets – those with five MW or more of demand reduction capability at a single Retail Delivery Point – must be registered as its own Demand Response Resource at the Nodal level.

[23] Section III.9.2.2 is being modified to include the consideration of Demand Response Resources when configuring Reserve Zones.

market rules to address situations such as this, it is possible that some of the Demand Response Assets of a Demand Response Resource will be located in different Reserve Zones. This could result in, for example, a Western Connecticut Demand Response Resource being paid to provide reserves in Southwest Connecticut Reserve Zone, even though most or all of its assets are located in the Connecticut Reserve Zone.

To address this potential situation, the ISO proposes a market rule change that will require all Demand Response Assets associated with a Demand Response Resource to be located within a single Dispatch Zone and Reserve Zone. This market rule change is reflected in Sections III.E2.1.1, III.E2.1.3, III.E2.1.4, and III.2.7A.

iv. Telemetry Requirement for Demand Response Resources Providing 10-Minute Reserves.

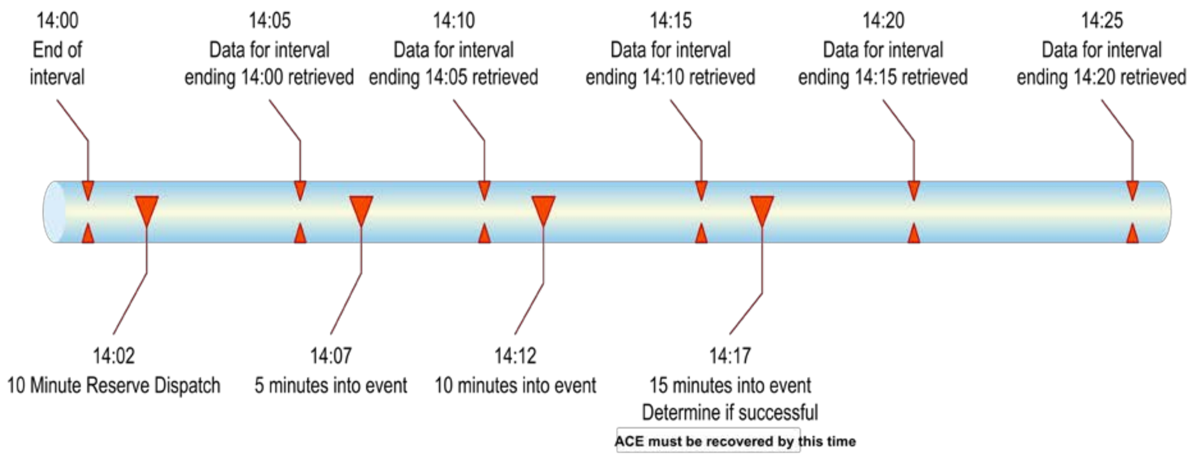
Q: Please explain the telemetry requirement for Demand Response Resources providing 10-Minute Reserves.

A: The ISO proposes that any Demand Response Resource claiming 10-minute Operating Reserve capability be required to provide at least one-minute interval data in real time for each Demand Response Asset associated with the Demand Response Resource. Market Participants with Demand Response Resources are also allowed to provide telemetry data at a faster rate. Under the rules presently in effect, Demand Response Resources and Real-Time Emergency Generation

Resources are required to provide five-minute interval data in real time. While five-minute data is sufficient for the provision of energy and 30-minute reserves, five-minute interval data does not provide adequate information in a timely manner from which to determine the Real-Time performance and capability of the Demand Response Resource in providing 10-minute reserve.

At the time of a reportable event, the ISO has 15 minutes from the start of that event to recover area control error (“ACE”) and avoid a NERC violation. Given this time constraint, system operators must know as soon as possible if resources providing 10-minute reserves have responded to a Dispatch Instruction when activated. If a resource does not deliver the dispatched amount of power within 10 minutes, system operators must determine whether it is necessary to dispatch another resource to recover ACE and avoid a NERC violation.

To illustrate the inadequacy of five-minute data to monitor the response of a resource providing 10-minute reserves, assume that five-minute data is reported to the ISO every five minutes (at the top of a clock hour and every five minutes thereafter) and a reportable event happens at 14:02 resulting in the dispatch of a resource providing 10-minute reserves. The figure below illustrates what happens:



After the resource is dispatched, five-minute interval data is reported to the ISO at 14:05 and 14:10. However, the data submitted at 14:05 shows the status of the resource at 14:00 because of the five-minute lag or latency between the end of the interval and the retrieval and transmission of the telemetry data (that is, the data submitted at 14:05 shows the status of the resource before it had been dispatched). In this example, therefore, a resource providing 10-minute reserves and reporting only five-minute data will be measured based on a single five-minute interval submitted at 14:10 (but this data reflects performance of the resource at 14:05, which is only three minutes into the event). This single data point would not be a sufficient basis upon which to determine the performance of the resource at the end of ten minutes.

One-minute real-time telemetry would provide adequate information to the system operator to measure the real-time performance of a Demand Response Resource within ten minutes of dispatch. Each Demand Response Asset associated with a Demand Response Resource providing ten-minute reserve must report one-minute real-time telemetry (the real-time telemetry of a Demand Response Resource is the sum of the real-time telemetry of its constituent Demand Response Assets).

The one-minute interval data will be used to monitor 10-minute resources in Real-Time and to determine performance in establishing CLAIM10 and CLAIM30 values, but will not be used to compute the Demand Response Baseline or to compute settlement. Rather, the five-minute telemetry data and five-minute revenue quality meter data will continue to be used to compute Demand Response Baselines and to compute settlement. Metering and telemetry requirements for Demand Response Resources are specified in Section III.E2.2. The revisions to address metering requirements for resources providing 10-minute reserves are addressed in Section III.E2.2.2.[24]

C. CHANGING THE DEMAND RESPONSE BASELINE ADJUSTMENT FACTOR

Q. By way of background, what is the Demand Response Baseline adjustment factor?

A: The Demand Response Baseline is the level at which the Demand Response Resource is expected to consume energy during the Operating Day when not being dispatched by the ISO to reduce demand. Under the existing baseline

[24] Other changes to Section III.E2.2.2 are explained later in this testimony.

calculation rules that will apply for the period during which Demand Response Resources are fully integrated into the energy and reserve markets, the Demand Response Baseline will be calculated using the methodology specified in Section III.8B of the Tariff. That methodology provides an estimate of the expected demand of a Demand Response Resource for each interval of the Operating Day by simulating a rolling ten-day average of meter data from previous days of the same day type on which the Demand Response Resource was not dispatched.[25] The resulting Demand Response Baseline is an estimated demand forecast for a Demand Response Resource.

The actual demand of the Demand Response Resource on any given day, however, may vary significantly from the estimated demand forecast. For example, the weather on a given Operating Day may be more extreme relative to the weather on previous days from which meter data were used to compute the demand forecast. For this reason, based on the actual demand in a day, an adjustment is added to the estimated demand forecast to better reflect the behavior of the resource during the Operating Day.

Q: **Why is the ISO proposing to change the Demand Response Baseline adjustment factor?**

[25] If meter data for more than seven of the prior 10 days of the same day type have been excluded from the Demand Response Baseline computation, meter data from the next day on which the Demand Response Resource was dispatched will be included in the Demand Response Baseline computation.

A: In addition to real-time telemetry and energy offer parameters, an estimate of expected demand, absent a Dispatch Instruction to reduce demand, is needed to determine the real-time capability of a Demand Response Resource to provide energy and reserves and to quantify the Demand Response Resource's response to a Dispatch Instruction. The current Demand Response Baseline methodology adjusts the baseline only once a day, after the Operating Day is over. A baseline adjustment that is calculated and applied after the Operating Day is over does not facilitate the determination of a Demand Response Resource's availability and performance in real time. That is, the estimated demand forecast available during the day, which is unadjusted, does not account for real-time conditions that may cause a Demand Response Resource's actual demand to vary significantly from its estimated baseline value. As a result, the estimated real-time availability of a Demand Response Resource to provide reserves during the Operating Day and/or the calculated real-time performance of a Demand Response Resource if dispatched to provide energy could be significantly over or under estimated. For this reason, a mechanism is needed to adjust the baseline in real time to provide a value that is meaningful in the calculation of a Demand Response Resource's real-time availability and performance during the Operating Day.

Q: Please summarize how the ISO proposes to adjust the Demand Response Baseline in real time.

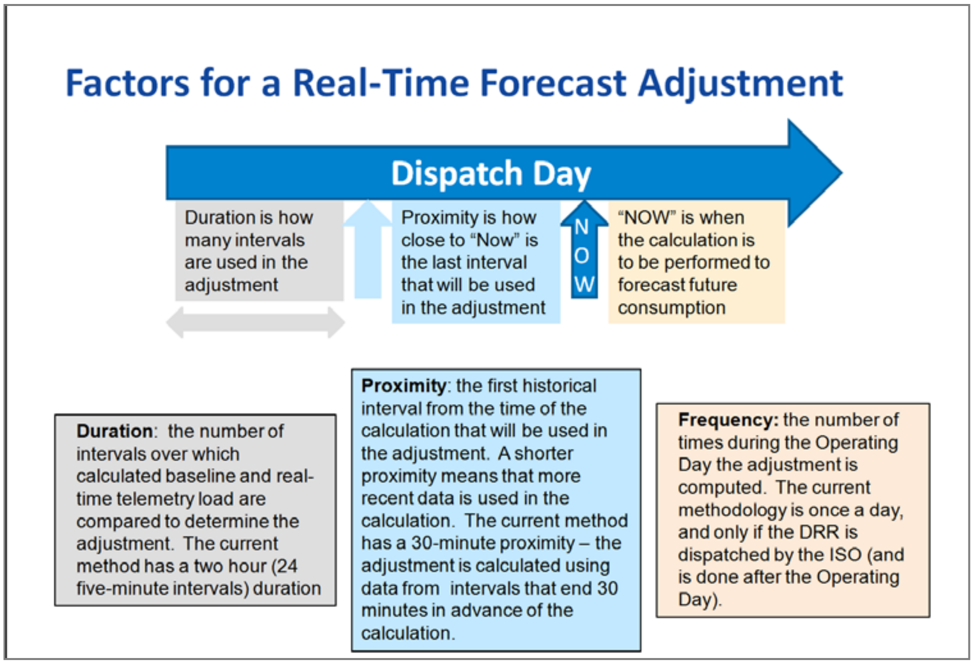
A: To forecast a Demand Response Resource's availability to provide reserves in real time and to determine its real-time performance in response to a Dispatch

Instruction, its demand will be forecasted using historical interval meter data ***and adjusted throughout the Operating Day using 5-minute real-time telemetry data.***

The initial estimated demand forecast will be computed using the method presently in Section III.8B. However, rather than updating the baseline once a day *after* the Operating Day is over, real-time telemetry data received during the Operating Day will be used to adjust the demand forecast at various points throughout the Operating Day. The adjustment procedure will be performed frequently and will be based on telemetry data from recent historical intervals.

Q: Was any quantitative research conducted to determine the best real-time Demand Response Baseline adjustment approach?

A: Yes. ISO New England engaged DNV GL to assist in analyzing Demand Response Baseline accuracy using different baseline adjustment methods. The figure below illustrates the factors considered in the analysis.



DNV GL analyzed the accuracy of different adjustment methods based on different combinations of proximities and durations:[26]

- Proximities of 3 to 7 intervals
- Duration of 3 to 24 intervals (where each internal is 5 minutes)

Adjusted Demand Response Baseline forecasts were analyzed for each day type (i.e., non-holiday weekdays, Saturdays, and Sunday/Holidays). The calculated adjustment was added to the forecast (which could increase or decrease the forecast) in future intervals to provide an estimate of expected demand. Notification, startup and interruption intervals were excluded from the calculation (during these intervals, the most recent adjustment, calculated prior to the

[26] This analysis also included the current baseline adjustment method, which is composed of a proximity of 7 intervals and a duration of 24 intervals.

notification period, was added to the forecast). Following the end of an interruption, the scheduled adjustment recalculations then resumed.

Generally, the results of the DNV GL analysis showed that real-time adjustments perform better (i.e., create an adjusted Demand Response Baseline that more accurately reflects actual demand) when proximity is closer, duration is shorter, and the adjustment is recalculated frequently throughout the Operating Day rather than only once a day. To determine the appropriate frequency with which the baseline adjustment should be calculated and applied, the analysis considered the following:

- data latency,
- calculation time, and
- how quickly information must be available to provide adequate situational awareness.

In view of these practical considerations, and in consultation with DNV GL, the ISO determined that a frequency of every 15 minutes is desirable.

Based on results of the analysis and practical considerations, the ISO proposes a real-time baseline adjustment using data with a proximity of three intervals and a duration of three intervals, where each interval is five minutes. The baseline adjustment will be calculated and applied at a frequency of every 15 minutes during the Operating Day. The adjustment will be calculated using five-minute interval-meter data from the three intervals that start 25 minutes before, and end 10 minutes before, the quarter hour interval when the adjustment calculation is performed. The adjustment factor is calculated in real time using real-time telemetry data. For settlement purposes, the adjustment factor is similarly calculated using revenue quality metering data.

During a response to a Dispatch Instruction, the adjustment factor is calculated using five-minute interval-meter data from the three intervals that start 25 minutes before, and end 10 minutes before, the Dispatch Instruction was issued.[27] Following the end of a dispatch, the adjustment factor for an asset will continue to be calculated using five-minute interval-meter data from the three intervals that start 25 minutes before, and end 10 minutes before, the Dispatch Instruction was issued, until sufficient time has elapsed to calculate the adjustment using post-dispatch meter data.

Q: Which provisions of the market rules are being modified to implement the recommended baseline adjustment approach?

A: Section III.8B.5 specifies the baseline adjustment mechanism and its application. This section was modified to implement the above-mentioned recommendations.

[27] As noted previously, the baseline adjustment would be calculated and applied at a frequency of every 15 minutes during the Operating Day. It is likely, however, that a Dispatch Instruction will be issued at some point in-between these quarter hour baseline adjustments. When implementing this market rule, therefore, the ISO will calculate the baseline adjustment using interval data from the most recent quarter hour baseline adjustment period before the issuance of the Dispatch Instruction.

D. INTEGRATING DEMAND RESPONSE RESOURCES INTO THE FORWARD RESERVE MARKET

Q: Will the proposed market rule changes allow a Demand Response Resource to participate in the Forward Reserve Market?

A. Yes. The ISO proposes that eligible Demand Response Resources be able to participate in the Forward Reserve Market ("FRM") and receive compensation for such participation. Similar to the market rule changes proposed by the ISO with respect to the energy market and Real-Time Operating Reserve, no changes to the basic design of the FRM are proposed. The rule changes described herein integrate Demand Response Resources into the existing FRM structure. Accordingly, Section III.9 of the Tariff is being modified to:

- Include Demand Reduction Offer parameters where Supply Offer parameters or Demand Bid parameters are referenced;
- Include Demand Reduction Offer data (adjusted for re-declarations) where Supply Offer or Demand Bid data are referenced;
- Specify the requirements and compensation calculations for Demand Response Resources in equivalent states to off-line and on-line generators; and
- Include Fast Start Demand Response Resources, as previously defined.

Telemetry and revenue quality meter data requirements for Demand Response Resources providing reserves were discussed previously and are addressed in Section III.E2.2.

To effectively integrate Demand Response Resources into the FRM, certain provisions of the Tariff are being modified to recognize the physical differences between Demand Response Resources and other resources (such as generation resources). These modifications include:

- Specifying the requirements that a Demand Response Resource must fulfill to be eligible for assignment to meet a Forward Reserve Obligation,
- Establishing how Demand Response Resource performance will be measured and compensated for participation in the FRM, and
- Defining CLAIM10 and CLAIM30 auditing rules for Demand Response Resources.

Q: Please explain the requirements that a Demand Response Resource must fulfill to be eligible for assignment to meet a Forward Reserve Obligation.

A: Eligibility requirements for Forward Reserve Resources are specified in Section III.9.5.2. Some of these requirements are based on the resource's state (e.g., off-line or on-line) and resource type (e.g., a Fast Start Generator or a Dispatchable Asset Related Demand ("DARD")). To integrate Demand Response Resources into the eligibility requirements of the FRM, the state of a Demand Response Resource equivalent to that of an off-line or on-line Resource must first be defined. As discussed previously:

- Demand Response Resources that have not been dispatched are equivalent to off-line generators, and
- Demand Response Resources that have been dispatched are equivalent to on-line generators.

Further, just as a Fast Start Generator is eligible to be a Forward Reserve Resource, a Fast Start Demand Response Resource should also be eligible to be a Forward Reserve Resource. With these principles in mind, Demand Response Resources have been integrated into Section III.9.5.2 as follows:

- Include Demand Response Resources that have not been dispatched wherever off-line Resources are referenced,
- Include Demand Response Resources that have been dispatched (i.e., have received a Dispatch Instruction) wherever on-line Resources are referenced,
- Include Fast Start Demand Response Resources that have not been dispatched wherever off-line, Fast Start Generators are referenced, and
- Include Demand Response Resources in references to Resources without a Capacity Supply Obligation.

With respect to the last bulleted item in the list above, Section III.9.5.2 (viii) of the presently effective market rules states that:

> The portion of the Resource without a Capacity Supply Obligation to which a Forward Reserve Obligation has been assigned must be offered into the Real-Time Energy Market in accordance with the provisions of III.13.6.1.1.2.

Section III.13.6.1.1.2, however, addresses the requirement that Supply Offers reflect accurate generating capacity resource operating characteristics, which is specific to generating resources. Therefore, Section III.9.5.2 (viii) is being modified to require that Demand Response Resources without a Capacity Supply Obligation to which a Forward Reserve Obligation has been assigned must be offered into the Real-Time Energy Market in accordance with Section III.13.6.1.5.2. Section III.13.6.1.5.2 addresses the requirement that Demand Reduction Offers must accurately reflect the operating characteristics of Demand Response Capacity Resources. In order to comply with this requirement, a Demand Response Resource to which a Forward Reserve Obligation has been assigned must re-declare its physical Demand Reduction Offer parameters during the Operating Day to reflect any changes that occur in real time. This requirement is equivalent to that applied to generating resources.[28]

Q: Please explain how Demand Response Resource performance will be measured and compensated for participation in the FRM.

A: The ISO proposes to treat a Demand Response Resource like other resources when measuring performance and determining compensation for participating in the FRM. This means that Market Participants with Demand Response Resources assigned to meet Forward Reserve Obligations will:

- Be paid at the same compensation rate,
- Be assessed comparable charges for non-performance, and
- Forego any Real-Time Reserve payment for MWs compensated as Forward Reserve.

Unlike other Forward Reserve Resources whose performance is either measured as output or consumption, Demand Response Resources perform by reducing load from the grid, injecting energy into the grid (i.e., Net Supply), or a combination of the two.[29] The portion of a Demand Response Resource's performance that is not associated with Net Supply will be multiplied by one plus the average avoided peak distribution losses when determining the amount of reserves delivered by the

[28] Similarly, Section III.1.7.20 was modified to require Market Participants with Demand Response Resources to continuously maintain its Offer Data during the Operating Day, to report to the ISO the anticipated availability of its resources, and to report to the ISO other factors that could reduce a resource's demand reduction capability for the pertinent Operating Day.

[29] Load reductions and Net Supply provided by a Demand Response Resource are measured at the Retail Delivery Points of each of the resource's constituent Demand Response Assets.

resource – i.e., when determining Forward Reserve Delivered Megawatts. For this reason, the measurement and compensation of a Demand Response Resource in the FRM must distinguish between performance that results from a reduction in load and performance that results from Net Supply.

Q: What sections of the market rules are being modified to allow for the measurement and compensation of Demand Response Resources assigned to meet a FRM obligation?

A: Various subsections in Section III.9.6 were modified. Section III.9.6 includes market rules related to:

- The dispatch and energy bidding of Forward Reserve Resources,
- The formula for determining the Forward Reserve Threshold Price (“FRTP”),
- The monitoring of Forward Reserve Resource offers by the Internal Market Monitor, and
- The calculation of on-line/off-line Forward Reserve Qualifying Megawatts and on-line/off-line Forward Reserve Delivered Megawatts.

Section III.9.6.1 references Supply Offers and Demand Bids, and is being modified to include equivalent requirements pertaining to Demand Reduction Offers of a Demand Response Resource.

No changes are required to Sections III.9.6.2 or III.9.6.3 to allow Demand Response Resources to provide Forward Reserves.

Section III.9.6.4 details the calculation of Forward Reserve Qualifying MWs ("FRQM") for off-line and on-line generators, and DARDs. The FRQM calculation relies on parameters in a resource's Supply Offer or Demand Bid. In order to calculate FRQM for a Demand Response Resource, this section is being changed to:

- Include Demand Reduction Offer parameters wherever Supply Offer parameters or Demand Bid parameters are referenced;
- Allow for the determination of a Demand Response Resource's FRQM by including Demand Reduction Offer data (adjusted for re-declarations) such as:
  - Interruption Cost,
  - Energy Offer,
  - Maximum Reduction, and
  - Minimum Reduction;
- Specify the calculation of FRQM for a Fast Start Demand Response Resource, which has not been dispatched:
  - The Demand Response Resource's offer price, which includes both the Demand Response Resource's energy offer price and the pro-rated Interruption Cost,[30] will be compared to the FRTP. FRQM is the amount of MWs, less than or equal to the offered Maximum Reduction, offered at a price that is at or above the FRTP;
- Specify the calculation of FRQM for a Demand Response Resource which has been dispatched:
  - The Demand Response Resource's energy offer price will be compared to the FRTP. FRQM is the amount of MWs, less than or equal to the offered Maximum Reduction and greater than the Minimum Reduction, offered at a price that is at or above the FRTP.

Section III.9.6.5 describes the calculation of Forward Reserve Delivered MWs ("FRDM") of a Forward Reserve Resource for each hour of the Real-Time Energy Market for each Reserve Zone. This provision is being updated to account for delivery from Demand Response Resources. FRDM for each

[30] The pro-rated Interruption Cost = Interruption Cost/Maximum Reduction. The pro-rated Interruption cost is calculated for each hour.

Demand Response Resource will be calculated by taking into account the Demand Response Resource's FRQM, Demand Reduction Offer parameters, and any re-declarations. FRDM for a Demand Response Resource that has not been dispatched is calculated as the minimum of:

- The amount of Forward Reserve that the undispatched Demand Response Resource can provide based upon the CLAIM10 and CLAIM30 values provided in the Demand Response Resource's Demand Reduction Offer,
- Forward Reserve Assigned Megawatts, or
- FRQM for the Demand Response Resource.

FRDM for a Demand Response Resource that has been dispatched is calculated as the minimum of:

- 10 or 30 times the Demand Response Resource Ramp Rate (to determine the amount of 10-minute or 30-minute reserves, respectively);
- Forward Reserve Assigned Megawatts; or
- FRQM for the Demand Response Resource.

At the time of settlement it must be determined what portion of the FRDM for a Demand Response Resource was not associated with Net Supply during the Operating Day. FRDM that was not associated with Net Supply will be multiplied by one plus the average avoided peak distribution losses.   To determine FRDM not associated with Net Supply:

- It will be assumed that a Demand Response Resource must first reduce its load from the electricity system up to the difference between the its Maximum Reduction and its Net Supply Limit[31] before providing Net Supply,

[31] The proportion of a Demand Response Resource's demand reduction expected to be provided through load reductions at the Retail Delivery Point versus Net Supply will be estimated using the results of that resource's most recent Seasonal DR Audit. At the time of the Seasonal DR Audit, the ISO would determine the ratio of total Net Supply to total demand reduction of the Demand Response Assets that are (continued...)

- The portion of the FRDM not associated with Net Supply will be calculated as the lesser of:
    - The total Forward Reserve Delivered Megawatts, or
    - The amount of load that the Demand Response Resource can reduce from the electric system as indicated from revenue quality meter data; and
- Any remaining FRDM in excess of the portion not associated with Net Supply will be capped at the Net Supply Limit.

Q: What are the consequences if a Market Participant fails to satisfy a Forward Reserve Obligation?

A: Section III.9.7 addresses the assessment of penalties to Market Participants that fail to satisfy a Forward Reserve Obligation. There are two types of penalties associated with delivery failure:

- A *Failure-to-Reserve Penalty* is assessed when the Market Participant fails to assign enough qualified resources to meet the reserve quantity it cleared in the FRM auction, and
- A *Failure-to-Activate Penalty* is assessed when any assigned resources fail to provide energy when activated.

Section III.9.7.1 specifies how the Failure-to-Reserve Penalty is calculated for a Market Participant based on the total quantity of the Forward Reserve delivered in real time by the assigned Resources. This calculation is not impacted by resource type. Therefore, no changes are required to this section of the Tariff.

(...continued)
mapped to the Demand Response Resource, where the total demand reduction of a Demand Response Asset is the sum of the load reduction measured at the asset's Retail Delivery Point and Net Supply produced. That ratio would be multiplied by the current offered Maximum Reduction of the Demand Response Resource to estimate the portion of the offered Maximum Reduction of a Demand Response Resource that would be provided through Net Supply. This quantity is defined as the "Net Supply Limit" – *see* Section I.2.2.

Section III.9.7.2 addresses how the Failure-to-Activate Penalty is assessed when a Resource that has been assigned to provide reserves fails to "activate" its Forward Reserve capability when requested to do so by the ISO during a contingency. Forward Reserve capability is activated when a Forward Reserve Resource is dispatched by the ISO to convert reserve capability into energy.

Under the existing rule structure, Forward Reserve Failure-to-Activate Megawatts for TMNSR for a Resource for each hour are the lesser of the following values:

- Maximum of (1) FRDM for TMNSR minus the actual amount of TMNSR energy delivered during activation, or (2) zero; or
- Maximum of (1) "Target Activation Megawatts for TMNSR" minus the actual amount of TMNSR energy delivered during activation, or (2) zero.

To incorporate Demand Response Resources into this calculation, Target Activation Megawatts for TMNSR for a Demand Response Resource will be calculated as follows:

- Target Activation Megawatts for a Demand Response Resource that has not been dispatched will be determined as the lesser of:
    - The minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period, or the Resource's Minimum Reduction, whichever is greater,[32]
    - The Resource's CLAIM10, or
    - The Resource's Offered CLAIM10.

- Target Activation Megawatts for a Demand Response Resource that has been dispatched will be determined as the lesser of:
    - The Demand Response Resource Ramp Rate times 10 minutes,

[32] The Desired Dispatch Point of a Demand Response Resource that has not been dispatched is zero.

- The Demand Response Resource's Maximum Reduction minus the Demand Response Resource's initial demand reduction at activation, or
- The minimum electronic Desired Dispatch Point sent to the Demand Response Resource during the 10 minute period minus the Demand Response Resource's initial demand reduction at activation.

Under the existing rule structure, Forward Reserve Failure-to-Activate Megawatts for TMOR for a Resource for each hour is the lesser of the following values:

- Maximum of (1) FRDM for TMOR plus FRDM for TMNSR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or (2) zero; or
- Maximum of (1) Target Activation Megawatts for TMOR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or (2) zero.

To incorporate Demand Response Resources into this calculation, Target Activation Megawatts for TMOR for a Demand Response Resource will be calculated as follows:

- Target Activation Megawatts for a Demand Response Resource that has not been dispatched will be determined as the lesser of:
  - The minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period, or the Resource's Minimum Reduction, whichever is greater,
  - The Resource's CLAIM30, or
  - The Resource's Offered CLAIM30.

- Target Activation Megawatts for a Demand Response Resource that has been dispatched will be determined as the lesser of:
  - The Demand Response Resource Ramp Rate times 30 minutes,
  - The Demand Response Resource's Maximum Reduction minus the Demand Response Resource's initial demand reduction at activation, or
  - The minimum electronic Desired Dispatch Point sent to the Demand Response Resource during the 30 minute period minus the Demand Response Resource's initial demand reduction at activation.

In determining Target Activation Megawatts for Demand Response Resources for settlement purposes, the portion of Target Activation Megawatts *not* associated with Net Supply will be multiplied by one plus average avoided peak distribution losses.

The portion of the Target Activation Megawatts *not* associated with Net Supply will be the lesser of:

- Total Target Activation Megawatts, or
- The amount of load reduced during activation.

The portion of the Target Activation Megawatts associated with Net Supply will be the lesser of:

- Total Target Activation Megawatts less the Target Activation Megawatts not associated with Net Supply, or
- The amount of Net Supply that the Demand Response Resource produced during activation.

Other sections of the Tariff related to the Forward Reserve Market (i.e., Sections III.9.7.3, III.9.8, and III.9.9) are not impacted by resource type. Accordingly, no changes are required to these sections of the Tariff to allow Demand Response Resources to participate in the FRM.

E. AUDITING DEMAND RESPONSE RESOURCES

Q: How will the capability of a Demand Response Resource to provide a 10- or 30-minute Operating Reserve product be established?

A: A Resource that provides reserves from an off-line state or an undispatched Fast Start Demand Response Resource that provides reserves must establish, through an audit, its ability to provide power within 10 or 30 minutes. A Resource's CLAIM10 value reflects the amount of power it is able to provide within 10 minutes; likewise, a Resource's CLAIM30 value reflects the amount of power it is able to provide within 30 minutes.

Section III.9.5.3 of the Tariff must be modified to establish market rules for the establishment of CLAIM10 and CLAIM30 values for Demand Response Resources. To accomplish this, wherever:

- The term "output" is used, the term "demand reduction" is inserted;
- The term "output level" is used, the term "demand-reduction level" is inserted; and
- The terms "Lead Market Participant", "Lead Market Participant or Designated Entity" are used, these terms were replaced, as appropriate, with the more general term "Market Participant" in order for this section to apply to all Resource types.

Section III.9.5.3.1 specifies how the CLAIM10 or CLAIM30 value of a Resource is determined. The determination of a CLAIM10/30 value is dependent on the measured capability of the Resource at 10 or 30 minutes. To be applicable to Demand Response Resources, this section is being modified to specify that the value measured for a Resource is the maximum output level or ***maximum demand-reduction level*** achieved at 10 or 30 minutes.

Additionally, the Desired Dispatch Point of a Resource is used in the calculation of the CLAIM10/30 value of a resource. Section I.2.2 of the Tariff defines Desired Dispatch Point as "the Dispatch Rate expressed in megawatts." A clarification is being made to the definition of the term "Dispatch Rate" to reflect that a Demand Response Resource offers to reduce demand rather than offering an output level.

Section III.9.5.3.2 details the CLAIM10/30 audit procedure. To allow the ISO to conduct CLAIM10/30 audits of Demand Response Resources, this section is being modified to include the terms "demand reduction" and "Market Participant" where appropriate.

Q: How is the CLAIM10/30 audit value of a Resource updated over time?

A: A CLAIM10/30 performance factor, which is used to adjust the initial CLAIM10/30 audit values to reflect actual performance, is computed based upon a Resource's historical ability to achieve its offered CLAIM10/30 from an off-line state or, for a Demand Response Resource from an undispatched state. A Resource's CLAIM10 or CLAIM30 performance factor is established based upon the 10 most recent ISO-issued initial electronic startup Dispatch Instructions as described below.[33] Resource performance factors are calculated on a weekly basis.

[33] Dispatch Instructions greater than three years old are excluded from this calculation.

Section III.9.5.3.3 describes how a Resource's CLAIM10/30 performance factor is established. The performance factor is based on the Resource's historical ability to achieve its CLAIM10/30 capability ("target value"). A Resource's current CLAIM10/30 value is based on its previously established value multiplied by the performance factor.

Q: Is Section III.9.5.3.3 being modified to allow for the computation of a performance factor for Demand Response Resources?

A: Yes. The measurement of whether a Resource achieves its target value references the output and Economic Minimum Limit of the Resource as inputs to the calculation of the performance factor. Output and Economic Minimum Limit are terms that are applicable to a generator, not a Demand Response Resource. Tariff language is being added to specify the performance factor calculation for a Demand Response Resource using demand reduction as a measure of performance rather than output, and Minimum Reduction in place of Economic Minimum Limit.

A dispatch is not utilized in the performance factor calculation if a Resource starts and subsequently performs a normal shut down, in response to a Dispatch Instruction to shut down, within the 10 or 30 minute period following the initial electronic startup Dispatch Instruction. Language is therefore being added to specify that a dispatch is not utilized in the performance factor calculation for a Demand Response Resource which ceases its demand reduction in response to a Dispatch Instruction to do so within the 10 or 30 minute period following the initial electronic startup Dispatch Instruction.

Q: Do the market rules allow Market Participants to reset a Resource's performance factor?

A: Yes. Section III.9.5.3.4 details the circumstances under which a restoration plan may be submitted to the ISO in order to restore the CLAIM10/30 operational capability of a resource that has been unable to reach its target value, and the procedure to restore the CLAIM10/30 capability. One of the conditions upon which a restoration plan may be submitted is a major overhaul scheduled and performed during a planned outage (approved in the ISO's annual maintenance scheduling process) that may result in an improvement in the resource's response to Dispatch Instructions.

Under the proposed revisions, Market Participants with Demand Response Resources must notify the ISO of a "scheduled curtailment" in advance of the curtailment (which in this context is comparable to a planned outage for a generator), and can submit a restoration plan to the ISO to the extent that improvements made during the scheduled curtailment are expected to improve the reliability of Demand Response Resource's response when dispatched.

Further, in order to integrate Demand Response Resources into Section III.9.5.3.4, the term "demand reduction" is being inserted wherever "target output" appears in order to reflect the appropriate target value for each resource type (output for generators and demand reduction for Demand Response Resources).

Q: Section III.1.5.2 of the current Tariff allows the ISO to audit any Supply Offer parameter that impacts the ability of a Generator Asset to provide Real-Time energy or reserves. Is the ISO modifying the Tariff to allow the ISO to similarly audit any Demand Reduction Offer parameter that impacts the ability of a Demand Response Resource to provide Real-Time energy or reserves?

A: Yes. As Resources that may provide Real-Time energy and reserves, Demand Response Resources should also be subject to ISO-Initiated Parameter Audits. The following changes are being incorporated into Section III.1.5.2 to allow the ISO to audit the offer parameters of Demand Response Resources that are analogous to Generator Asset Supply Offer parameters.

A new section is being added to the Tariff specifying the Demand Reduction Offer parameters that may be audited and how the Demand Response Resource will be evaluated. The evaluation will be based on the Demand Response Resource's ability to achieve the offered value. Demand Response Resource parameters subject to audit are:

- Maximum Reduction,
- Demand Response Resource Ramp Rate,
- Demand Response Resource Start-Up Time,
- Demand Response Resource Notification Time,
- CLAIM10, and
- CLAIM30.

Further, relevant terms that apply to Demand Response Resources (e.g., Market Participant, Demand Response Resource, Demand Reduction Offer, and demand-reduction level) are being included in sections that specify:

- Audits based upon historical data,
- Unannounced audits,
- Restrictions based on audit results,
- Submission of a plan to restore a parameter, and
- ISO New England actions in response to submission of a restoration plan.

Q: Are changes being made to the market rules governing the auditing of Demand Response Resources in the Forward Capacity Market?

A: Yes. Under the current Forward Capacity Market rules, a Market Participant can fulfill a Capacity Supply Obligation with a Demand Response Capacity Resource. A Demand Response Capacity Resource is composed of one or more Demand Response Resources that are located in the same Dispatch Zone. A Market Participant with a Demand Response Capacity Resource fulfills its Capacity Supply Obligation by offering an amount of capacity, through its Demand Response Resources, into the co-optimized energy/reserve market, which is at least equal to its Capacity Supply Obligation or its resources' full physical capability if the Capacity Supply Obligation amount is not available. These Demand Response Resources are then dispatched by the ISO in accordance with each resource's Demand Reduction Offer.

As explained previously, a Demand Response Resource is composed of Demand Response Assets located within the same Dispatch Zone and Reserve Zone.

Demand Response Assets are the actual end-use customers (residential, commercial or industrial customers) that reduce load from the grid or provide Net Supply to the grid.

Audits of Demand Response Capacity Resources are conducted by individually dispatching their constituent Demand Response Resources, which participate in the energy market. These audits, referred to as Seasonal DR Audits, are conducted for the summer and winter seasons given that most Demand Response Resources have weather-sensitive demands that are likely to perform very differently between seasons.

The existing Tariff language could be interpreted to require that all of the Demand Response Resources associated with a Demand Response Capacity Resource with a Capacity Supply Obligation be audited by dispatching all Demand Response Resources simultaneously. However, such a requirement would not reflect the manner in which Demand Response Resources would likely be dispatched in practice once these resources are fully integrated into the energy and reserves markets. Firstly, each Demand Response Resource that is associated with a Demand Response Capacity Resource could have different Demand Reduction Offers, which would place each Demand Response Resource on a different part of the energy market supply curve and would likely result in such resources being dispatched in a non-coincident fashion. Secondly, since Demand Response Resources will be able to provide Operating Reserve, it is possible that during a

Shortage Event some Demand Response Resources that are part of a Demand Response Capacity Resource would be dispatched to provide energy and others would be designated to provide Operating Reserve. Accordingly, Section III.13.6.1.5.4.2 of the Tariff is being clarified so that Demand Response Resources associated with a Demand Response Capacity Resource will not have to be audited simultaneously.

Further, Section III.13.6.1.5.4.3.3.1 is being modified in three ways to allow for more options by which to establish Seasonal DR Audit values. First, this section is being modified to permit a Market Participant to use the performance of a Demand Response Resource during a Shortage Event in place of a Seasonal DR Audit provided that any of the resource's constituent Demand Response Assets that are on a forced or scheduled curtailment during the event are assessed a zero audit performance. In calculating the availability score of a resource during a Shortage Event, the Demand Response Resource receives credit for the reduced demand of the Demand Response Asset that is on a scheduled or forced curtailment. However, it would not be appropriate to use the performance of a Demand Response Resource with assets on a scheduled or forced curtailment as its Seasonal DR Audit value. This is because the audit's purpose is to measure the performance of the Demand Response Resource in response to dispatch when its assets are in its normal mode of consuming energy from the electric grid. Forced and scheduled curtailments are limited events that do not reflect normal demand during the vast majority of the year. Accordingly, the ISO proposes to allow the use of the performance of a Demand Response Resource during a Shortage Event in place of a Seasonal DR Audit provided that any constituent Demand Response Asset on a forced or scheduled curtailment during the event is assessed a zero audit performance.

Second, Section III.13.6.1.5.4.3.3.1 is being modified to permit a Market Participant to use the CLAIM10 or CLAIM30 value at the time of a Shortage Event for purposes of establishing the Audited Demand Reduction value of the Demand Response Resource. It is possible for a Shortage Event to occur before a new Demand Response Resource is able to conduct a Seasonal DR Audit to establish an Audited Demand Reduction value. If the resource was not dispatched during the Shortage Event at a level equal to its Maximum Reduction, then absent an Audited Demand Reduction value the assessed availability of the resource during the Shortage Event may be established at a level below its true capability. However, if a CLAIM10 or CLAIM30 value were available at the time of the Shortage Event (which is possible given that the ISO typically conducts CLAIM10/30 audits within five days of the request) the modified market rule would allow the Market Participant to set the Audited Demand Reduction of the Demand Response Resource equal to its CLAIM10 or CLAIM30 value. It should be noted that the ISO would endeavor to coordinate Seasonal DR Audits and CLAIM10/30 audits so a single audit of a Demand Response Resource could be used to establish the resource's Audited Demand Reduction value as well as its CLAIM10 and/or CLAIM30 values.

Third, Section III.13.6.1.5.4.3.3.1 is being modified to allow the use of a Demand Response Resource's CLAIM10 or CLAIM30 audit result that was conducted during a DR Auditing Period in place of requesting a Seasonal DR Audit of that resource on the condition that the audit was conducted in a manner that meets the requirements of a Seasonal DR Audit. This new provision helps reduce the need to conduct multiple audits of a resource in the same season to fulfill different purposes.

In summary, the sections of the Tariff impacted by clarifying the manner in which Seasonal DR Audits of Demand Response Resources are conducted as described above include Sections III.13.6.1.5.4.2, III.13.6.1.5.4.3.3.1, III.13.6.1.5.4.6, and III.13.7.1.5.10.1.1.

F. IMPLEMENTING RELATED MARKET RULE CHANGES

Q: Does the ISO propose to implement other market rule changes related to Demand Response Resources at this time?

A: Yes. These related market rules changes include:

- Integrating the recent Demand Response Baseline changes that were made during the transition period into the Demand Response Baseline rules that are applicable for the full integration of demand response into the wholesale markets. These changes include:
    - Establishing the Demand Response Baseline of Demand Response Assets experiencing a scheduled or a forced curtailment, and establishing rules for resetting Demand Response Baselines (*see* ER14-727-000);
    - Constraining the adjusted Demand Response Baseline of Demand Response Assets capable of producing Net Supply (*see* ER14-1659-000);

- Modifying the metering requirements for behind-the-meter generators; and
- Modifying the metering requirements for Demand Response Assets.

Q: Please explain the Demand Response Baseline changes that take into account scheduled and forced curtailments of Demand Response Assets.

A: Section III.8A, which governs Demand Response Baselines between now and the time Demand Response Resources are fully integrated into energy and reserve market in June 2017, was recently changed to address the accuracy of Demand Response Baselines during and after days on which a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset is on a scheduled curtailment (e.g., scheduled maintenance of energy consuming equipment) or forced curtailment (e.g., transmission or distribution outage).[34] The ISO proposes to incorporate the same changes into Section III.8B to be applicable to Demand Response Assets and Real-Time Emergency Generation Assets beginning June 1, 2017.

Baseline accuracy during and immediately following a forced or scheduled curtailment of a Demand Response Asset or a Real-Time Emergency Generation Asset is achieved by requiring the Demand Designated Entity to submit, on the days of the curtailment, meter data values for the affected asset equal to the last unadjusted Demand Response Baseline computed *prior* to the forced or scheduled

[34] *ISO New England Inc. and New England Power Pool*, Demand Response Baseline Changes, Docket No. ER14-727-000, (December 20, 2013); http://www.iso-ne.com/regulatory/ferc/filings/2013/dec/er14-727-000_drbaseline_chg_12-20-2013.pdf.

curtailment, instead of actual meter readings. Submitting meter data values equal to the last unadjusted baseline prior to the scheduled or forced curtailment preserves the asset's baseline during the curtailment.

To implement these changes beginning June 1, 2017, Section III.8B.6.1 is being added to include the definition of and parameters for forced and scheduled curtailments. A Market Participant with a Demand Response Asset or a Real-Time Emergency Generation Asset may notify ISO New England of a forced or scheduled curtailment. A Market Participant may notify the ISO of a scheduled curtailment at least seven calendar days before the start of any reductions. For Demand Response Assets or Real-Time Emergency Generation Assets with a Maximum Interruptible Capacity of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The length of a scheduled curtailment must be a minimum of a single calendar day and may not exceed a total of 14 calendar days per Capacity Commitment Period.

Further, Section III.8B.6.2 is being added to specify the meter data submission requirements for each calendar day on which a Demand Response Asset or a Real-Time Emergency Generation Asset is on a forced or scheduled curtailment. For such days, the Demand Designated Entity of the Demand Response Asset or Real-Time Emergency Generation Asset will submit to the ISO meter data values equal to the unadjusted baseline calculated for the first day of the forced or scheduled curtailment for all intervals *excluding* those intervals in which:

- The Demand Response Resource with which the Demand Response Asset is associated was dispatched during the period of a Shortage Event as defined in Section III.13.7,
- The Demand Response Resource with which the Demand Response Asset is associated was dispatched in real time pursuant to Section III.E2 on the first day of an unanticipated forced curtailment, or
- The Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated was dispatched to reduce demand pursuant to Section III.13.

During the above-mentioned excluded intervals, the proposed market rule requires (as specified in Section III.8B.6.3) that actual meter readings be submitted, which reflects the actual demand of the asset. This would allow the ISO to assess the demand reduction delivered by the asset during the forced or scheduled curtailment. This treatment is appropriate because an asset on a forced or scheduled curtailment during a Shortage Event or a capacity deficiency event (as defined in Section III.13) has reduced its demand from the grid and, therefore, has provided its capacity to the grid.

With respect to the energy/reserve market, however, a Demand Response Asset on a forced or scheduled curtailment cannot be dispatched in real time to balance supply and demand. So the proposed market rule limits the contribution of a Demand Response Asset on a forced or scheduled curtailment from the performance of its associated Demand Response Resource in the energy market. By definition, a scheduled curtailment will be known in advance and can be anticipated. Accordingly, the proposed market rule requires that the Market

Participant submit meter data values for the affected asset equal to its last unadjusted baseline for each day on which the asset is on the scheduled curtailment even if the resource to which the asset is associated is dispatched in the energy market.[35] The asset cannot contribute to the performance of the resource if the meter data values being reported for the asset during dispatch are equal to its baseline.

However, most forced curtailments are random occurrences that cannot be anticipated. If a Demand Response Resource is dispatched in the energy market on a day that some of its constituent assets experience an unanticipated forced curtailment, the proposed approach is for the Market Participant to submit data values similar to that submitted for Shortage Events and capacity deficiencies as described above. This will result in the Demand Response Asset contributing to the performance of the Demand Response Resource to which it is associated. However, most forced curtailments are rare and short in duration, so any associated energy settlement will be limited. If the forced curtailment is prolonged (e.g., major storm damage to the transmission and distribution system), any subsequent days after the first day of the forced curtailment can be anticipated. Therefore, the proposed market rule requires Market Participants to submit meter data values equal to the last unadjusted baseline for any subsequent days of a forced curtailment, at which point the asset could no longer contribute to the performance of the Demand Response Resource to which it is associated.

[35] With the exception of Shortage Events and capacity deficiency events as previously noted.

This provision limits the risk of excessive energy payments for more extensive forced curtailments, and avoids the development of complex software to neutralize the effect of the asset's contribution due to a forced curtailment once that curtailment became known.

Q: Please explain the market rule changes for resetting Demand Response Baselines given a significant change in the load, generation, or reported meter data at an existing Demand Response Asset or Real-Time Emergency Generation Asset.

A: In Docket No. ER14-727-000, the ISO proposed and the Commission accepted changes to Section III.8A.1, which govern the resetting of a Demand Response Baseline given a significant change in the load, generation, or reported meter data at an existing Demand Response Asset or Real-Time Emergency Generation Asset. Since Section III.8A applies to the transition period, the ISO is now proposing to incorporate into Sections III.8B.2 and III.E2.8 (i.e., the rules that apply to the full integration of demand response into the wholesale markets) the same market rule changes accepted by the Commission in Docket No. ER14-727-000. Under these changes, a Demand Response Baseline will be reset using the baseline calculation methodology that applies for initially setting the baseline whenever a significant change in load, generation, or reported meter data at an existing Demand Response Asset or Real-Time Emergency Generation Asset occurs.

Q: Please explain the Demand Response Baseline changes that constrain the adjusted Demand Response Baseline of Demand Response Assets capable of producing Net Supply.

A: Recently, Section III.8A of the market rules was modified to place constraints on the adjusted Demand Response Baseline for assets capable of providing Net Supply.[36] Prior to this change, the floor on the adjusted Demand Response Baseline was zero MW. The majority of demand response assets are not capable of producing Net Supply because they do not have behind-the-meter generation, or because they do not have an interconnection that supports energy injections into the grid. For such assets, the zero MW floor on the adjusted Demand Response Baseline recognizes that these assets are physically incapable of providing Net Supply. However, a zero MW floor on the adjusted Demand Response Baseline of assets capable of Net Supply could result in an over-estimated baseline, and consequently an over-payment. That is, if an asset is capable of Net Supply, but its adjusted Demand Response Baseline is not allowed to go below zero MW,[37] the resulting baseline could overestimate the asset's normal consumption/production activities and consequently overestimate any demand reductions provided in response to Dispatch Instructions.

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[36] *ISO New England Inc. and New England Power Pool*, Demand Response Baseline Net Supply Changes, Docket No. ER14-1659-000 (April 4, 2014); http://www.iso-ne.com/regulatory/ferc/filings/2014/apr/er14-1659-000_dr_base_net_sup_chges.pdf.

[37] Note that in this section, a negative meter reading and a negative Demand Response Baseline reflects the provision of Net Supply.

The issue was addressed by revising Section III.8A so that the zero MW floor on adjusted Demand Response Baselines only applies to assets that are not capable of providing Net Supply. A new provision was added to Section III.8A.4.4 to address assets that are capable of providing Net Supply. For these assets, the floor on the adjusted Demand Response Baseline is based on the maximum Net Supply that the asset can push back into the grid, which is defined by the asset's generator interconnection agreement.

The ISO now proposes that the same changes be incorporated into Section III.8B, which would be applicable to Demand Response Assets beginning June 1, 2017. Accordingly, Section III.8B.5(d) is being modified so that:

- For Demand Response Assets that cannot produce Net Supply, the adjusted Demand Response Baseline may not be less than zero, and
- For Demand Response Assets that can produce Net Supply, the adjusted Demand Response Baseline may not be less than the maximum amount in MW that the asset is allowed to push back into the electric system per the applicable generator interconnection agreement, and shall not exceed the asset's Maximum Facility Load.

Q: Please explain the proposed changes to the metering requirements for behind-the-meter generators.

A: Under the present Tariff, Real-Time Demand Response Assets may consist of a controllable facility demand measured at the Retail Delivery Point of the asset, and may consist of directly-metered Distributed Generation located behind the

Retail Delivery Point.[38] Accordingly, some complex facilities may have several Real-Time Demand Response Assets located at and behind the same Retail Delivery Point. Accommodating multiple Real-Time Demand Response Assets at the same facility caused the ISO to develop and administer complex metering schemes to ensure that the energy generated by a Real-Time Demand Response Asset consisting of directly-metered Distributed Generation was not also being credited to another Real-Time Demand Response Asset located at the Retail Delivery Point.

Many of these issues are resolved when Demand Response Resources are fully integrated into the energy and reserve markets given that all Demand Response Assets must be measured at the Retail Delivery Point. Thus, under the existing market rules applicable to full integration, behind-the-meter Demand Response Assets will not be permitted, and there can be only one Demand Response Asset per Retail Delivery Point. Such a change was reasonable because actions occurring behind the Retail Delivery Point of a Demand Response Asset may have no impact on the electric grid and thus cannot affect the balance of supply

[38] *See* Section III.13.1.4.3.2. The current metering requirements for Capacity Commitment Periods commencing before June 1, 2017 – i.e., prior to full integration – were clarified in this section of the Tariff. Here, the output of generators comprising a Real-Time Demand Response Asset located behind the retail delivery point must be directly metered and reported to the ISO in real time as a single set of interval meter data at an interval of five-minutes. Also, the output of the generators comprising a Real-Time Emergency Generation Asset must be directly metered and reported to the ISO as a single set of interval meter data, provided that the Market Participant may instead meter the Real-Time Emergency Generation Asset at the retail delivery point if there is no other Real-Time Emergency Generation Asset, Real-Time Demand Response Asset or other generator whose output can be controlled at the same facility.

and demand on the wholesale market.[39] Actions of a Demand Response Asset are felt on the electric grid only at the point where that asset is connected to the grid (i.e., at the Retail Delivery Point).

While the market rules will no longer allow a behind-the-meter generator to be registered as a Demand Response Asset, the market rules continue to require that such generators report 5-minute interval meter data to the ISO.[40] The purpose of this requirement is to monitor behind-the-meter generation production to ensure that the Demand Response Asset's adjusted Demand Response Baseline, measured at the Retail Delivery Point, is not being manipulated.

Meanwhile, the electric grid is presently witnessing a proliferation of behind-the-meter generation, particularly renewable energy resources such as solar photovoltaic panels at residential, commercial and industrial facilities. As currently written, a Demand Response Asset with a solar panel generating energy behind-the-meter would be required to install five-minute metering on that panel. Not only would the additional expense be likely to discourage the customer from

[39] For example, a behind-the-meter generator that increases production will have no impact on the electric grid if consumption at the same facility also increases by the same amount, and vice versa.

[40] The only exception to this rule is found in Section III.13.1.4.3.2. This section was clarified to require that Real-Time Emergency Generation Assets must be directly metered and reported to the ISO as a single set of interval meter data – because Real-Time Emergency Generation Assets may be located at a facility with a Demand Response Asset, the emergency generator must be metered directly to establish its performance. However, if there is no other Real-Time Emergency Generation Asset, Real-Time Demand Response Asset or other generator whose output can be controlled at the same facility, this provision allows the Market Participant to instead meter the Real-Time Emergency Generation Asset at the Retail Delivery Point. Meter data associated with the Real-Time Emergency Generation Asset must be recorded and reported by the Market Participant to the ISO in Real-Time at an interval of five minutes.

participating in the market as a Demand Response Asset, the requirement appears to be unnecessary for monitoring potential Demand Response Baseline manipulation. To manipulate the Demand Response Baseline as discussed above, the behind-the-meter generator's output must be reduced during the baseline adjustment period. Only those generators whose output can be controlled (i.e., decreased or increased regardless of energy consumption at the facility) can be used to manipulate the adjustment of the Demand Response Baseline. Other generators whose output cannot be controlled (e.g., intermittent resources such as solar or wind, or resources whose electrical output is directly proportional to the energy consumption of the facility) cannot readily manipulate the Demand Response Baseline as described above. Further, many customers have emergency generators whose output can be controlled, but that cannot operate synchronized to the grid. That is, in order to operate an emergency generator, these facilities must isolate the load of the facility served by the emergency generator from the grid, and thus also cannot manipulate the baseline using such generators.

Accordingly, the ISO proposes to modify the metering requirement for Demand Response Assets with behind-the-meter generation – *see* Section III.E2.2.2. Rather than requiring that all behind-the-meter generators be metered, the ISO proposes market rule changes that require only those with controllable output be metered (with the exception of emergency generators that cannot operate synchronized to the grid). Market Participants would report a single set of generator output data to the ISO at an interval of five minutes or less.[41] Further, Market Participants will no longer need to submit these data to the ISO in real time. The ISO does not need to receive these data in real time to perform analysis of potential Demand Response Baseline manipulation. Rather, these data must be submitted to the ISO by the end of the Correction Limit for the Data Reconciliation Process.

Because the proliferation of behind-the-meter generation (primarily in the form of solar photovoltaics) is presently occurring, the ISO made similar modifications to the current metering rules for Real-Time Demand Response Assets – *see* Sections III.E1.2.1 and III.E1.2.4.

Q: Please explain the proposed changes to the metering requirements for Demand Response Assets.

A: The ISO is modifying several sections of the market rules (i.e., Sections III.13.1.4.3.2, III.E2.2.1, III.E2.2.2, III.E2.2.3 and III.E2.2.4) to differentiate telemetry from revenue quality metering and to implement improved metering requirements.

The bulk of the Demand Response Asset metering changes are found in Section III.E2.2. Section III.E2.2.1 is being revised to better ensure the integrity of

[41] The current market rule requires Market Participants to report to the ISO a single set of generator output data ***in real time*** at an interval of five minutes or less.

revenue-quality meter data submitted by Market Participants for their Demand Response Assets. In some cases, Market Participants use the electric distribution company's revenue-quality meter, which is used by the electric distribution company for billing purposes, as the source of data for wholesale settlement. Such meters are subject to state-regulated standards of accuracy, calibration, testing, etc., and the data submitted by Market Participants to the ISO for wholesale settlement can be (and is) cross-checked against customer billing data maintained by the electric distribution company. Accordingly, additional provisions are not needed in the Tariff to better ensure the integrity of Market Participant submitted meter data if the source of the data is the electric distribution company's revenue-quality meter.

In other cases, however, the Market Participant installs their own meters on Demand Response Assets and uses data derived from those meters for wholesale settlement purposes. To better ensure the integrity of these data, more detailed provisions are being added in Section III.E2.2.1 that require the Market Participant to validate and provide documentation to the ISO that any difference between the values recorded by the Market Participant's meter and the values recorded by the distribution company's billing meter is within an acceptable tolerance range (i.e., that the difference between the Market Participant's and the electric distribution company's meter data in the same timeframe is within ± 2.0%). Further, Section III.E2.2.1(d) requires Market Participants to provide documentation to the ISO of any inaccuracies found in distribution company meter data and of any communications with the distribution company to address these inaccuracies.

Section III.E2.2.2 is being modified in three ways. First, as previously discussed, telemetry-quality data on controllable behind-the-meter generation will no longer be required in real time, with the exception of any directly-metered Real-Time Emergency Generation Assets. Second, if the Market Participant does not use the electric distribution company's revenue-quality meter to obtain real-time telemetry, the Market Participant must specify the manufacturer and the model of the device used. Further, the requirement to report telemetry device specifications to the ISO has been made more general (i.e., reporting device specifications is no longer limited to only the asset registration process) given that Market Participants might change the telemetry device at some point after the asset registration process.

Third, this and other sections discussing the demand response metering requirements (including Sections III.13.1.4.3.2, and III.E1.2.1) are being modified to eliminate ***the option*** that more granular interval data other than five-minute data could be submitted to the ISO. This modification is necessary given that the ISO's baseline-telemetry system, which is used to compute Demand Response Baselines, is designed to use five-minute interval data only.[42]

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[42] In addition to five-minute data, Market Participants must report telemetry values at least every one minute for Demand Response Resources providing ten-minute reserves as previously discussed. One-minute data will be used to monitor the Real-Time status of a Demand Response Resource providing 10-

(continued...)

G. INCORPORATING OTHER MINOR RULE CHANGES

Q: Does the ISO propose other conforming and/or non-substantive market rule changes at this time?

A: Yes. To allow Demand Response Resources to participate in the energy markets and provide Operating Reserve, the ISO conducted a comprehensive review of the Tariff and found that several conforming and/or non-substantive market rule changes should be made to further clarify the Tariff. These include:

- **Section I.2.2** – Several defined terms were modified as follows:
    - **Dispatch Instruction –** This term is being modified to include consideration of Demand Reduction Offer parameters.
    - **Lead Market Participant –** This term is being modified to include the entity authorized to submit Demand Reduction Offers.
    - **Offered CLAIM10 and Offered CLAIM30 –** These definitions are being clarified by applying more appropriate (and equivalent) terminology to different resource types (i.e., an "off-line" state for generating Resources, and a "has not been dispatched" state for Demand Response Resources and Dispatchable Asset Related Demands).
    - **Ten-Minute Non-Spinning Reserve (TMNSR) –** The word "unit" (as in generating "unit") is being changed to the defined term "Resource." Also, the tautology "generating units that are either not electrically synchronized or synchronized to the New England Transmission System" is being deleted from the definition.
    - **Ten-Minute Spinning Reserve (TMSR)** – The word "unit" (as in generating "unit") is being changed to the defined term "Resource." The phrase "that is electrically synchronized to the New England Transmission System" is being inserted or deleted as context requires.

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minute reserves and to develop CLAIM10 values; however, five-minute data (not one-minute data) will continue to be used to develop Demand Response Baselines.

- **<u>Thirty-Minute Operating Reserve (TMOR)</u> –** The word "unit" (as in generating "unit") is being changed to the defined term "Resource." Also, the tautology "generating units that are either not electrically synchronized or synchronized to the New England Transmission System" is being deleted from the definition.

- **<u>Sections III.1.5.2, III.1.7.7, III.1.7.17, III.1.10.1A, III.3.2.1, and III.9.6.1</u>** – Several typographical errors are being corrected, and unnecessary or incorrect modifiers and phrases are being deleted. For example, the defined term "Dispatch Instruction" is sometimes modified by the words "ISO-issued" or "ISO." Such a modifier is unnecessary because Dispatch Instruction is a defined term in the Tariff, which means directions given by the ISO to Market Participants. The phrase "of Market Rule 1" is being deleted where that phrase modified a Tariff section reference (this phrase is unnecessary). The phrase "by the ISO" is being deleted where that phase refers to the buying and selling of energy.

- **<u>Section III.1.5.2</u>** – A number is being inserted in the last line of the numbered list in this section.

- **<u>Sections III.1.5.2(h), III.9.5.3.2, and III.9.5.3.4</u> –** Where appropriate, the terms "Lead Market Participant", "Lead Market Participant or Designated Entity" are being replaced with the more general term "Market Participant" in order for these sections to apply to all Resource types.

- **<u>Section III.1.7.8</u>** – This section is being modified to be consistent with Sections III.E2.3 and III.E2.4 with respect to the prohibition that Demand Response Resources not be allowed to Self-Schedule demand reductions.

- **<u>Section III.1.7.17</u> –** A reference to Market Rule 1 is being added to this section.

- **<u>Section III.1.7.19A</u> –** A reference to Section III.10 is being added to this section.

- **<u>Section III.1.7.20</u>** – The "&"is being replaced with the word "and."

- **<u>Section III.1.10.1A –</u>** The typographical error "theamount" is being corrected.

- **<u>Sections III.1.10.1A, III.1.10.2, III.1.11.1, III.1.11.3, III.2.2, III.2.4, III.2.5, and III.2.6</u>** – These sections are being modified to reflect the integration of Demand Response Resources into the energy markets.

- **<u>Section III.2.4(b)(iii)</u>** – This section is being modified to make clear that a generating resource operating "at or" above its economic minimum is eligible to set price.

- **Sections III.2.4(c), (d) and (e)** – Section III.2.4(c) is being clarified so that the ten percent tolerance range for a generator to be considered following Dispatch Instructions is above "or below" the Desired Dispatch Point. Section III.2.4(d), which applies to DARDs, is similarly modified. Section III.2.4(e) is being added to the Tariff, which establishes the same plus or minus ten percent tolerance range within which a Demand Response Resource must be operating in order for the resource to be considered to be following Dispatch Instructions. Also, the word "Section" is being added before each Tariff section reference.

- **Section III.2.7** – The development of LMPs for Dispatch Zones is being added to this section. Because Demand Response Resources consist of aggregations of Demand Response Assets located in the same Dispatch Zone, LMPs for Dispatch Zones must be computed.

- **Section III.2.7A(b) –** The term "Node" is being replaced with "Location" to recognize that unit-specific opportunity costs resulting from the re-dispatch of resources to maintain sufficient levels of Operating Reserve need to be measured at different Locations as a function of resource type (i.e., a generator is priced at a Node, and a Demand Response Resource is priced at either a Node or a Dispatch Zone pursuant to the asset aggregation requirements outlined in Section III.E2.1).

- **Section III.3.1** – This section is being modified to refer to Section III.E2.9, which sets forth the Day-Ahead Energy Market and Real-Time Energy Market settlement rules for Demand Response Resources.

- **Section III.3.2.1** – A phrase at the end of the first paragraph is being shortened for clarity, and the phrase "calculated in accordance with" is being added in front of certain Tariff section references.

- **Section III.3.2.6** – Demand reduction deviations are being added to the list of potential deviations that could receive an allocation of emergency energy costs and revenues. The word "generation" is being replaced by the term "generating Resource" in the phrase "generation and Demand Response Resources."

- **Section III.3.2.7** – This section is being modified to refer to Section III.E2 as the source for the charges and credits associated with Demand Response Resources.

- **Section III.8A.4.4** – The word "hourly" is being deleted because the maximum amount of power that a customer with a behind-the-meter generator is allowed to push back into the electric system per the applicable generator interconnection agreement is stated in MW, not in maximum hourly MW.

- **<u>Section III.8B.3 and III.8B.4</u> –** Non-substantive, clarifying changes and Tariff section references are being added to these sections.

- **<u>Section III.8B.5(c)</u> –** The word "averge" is being corrected.

- **<u>Section III.9.2.2</u> –** The term Dispatchable Asset Related Demand is being inserted where it was missing.

- **<u>Section III.9.5.1</u> –** A modification is being made to this section to clarify that Ownership Shares in a Resource applies to generating Resources.

- **<u>Section III.9.5.2(a)</u> –** This section is being clarified by eliminating unnecessary terminology (i.e., the phrase "off-line or on-line" was unnecessary), and by modifying the term "Resource" to "generating Resource" where a rule provision specifically applies to generating Resources.

  Further, unnecessary tautologies in subsections (iv) and (vii) of the currently effective Tariff are being deleted. These include sentences in which a Resource has a "Capacity Supply Obligation for all, some, or none" of its capability, and phrases referring to a portion of a Resource "with or without a Capacity Supply Obligation." In subsection (ix), the phrase "without a Capacity Supply Obligation, or the portion of a Demand Response Resource" is unnecessary and is being deleted from the Tariff.

- **<u>Section III.9.5.3.1.2(c)</u> –** This section of the Tariff is being deleted because it is obsolete.

- **<u>Section III.9.6.3</u>** – A reference to Section III.A.9.4 is being corrected to refer instead to Section III.A.13.4.

- **<u>Section III.9.6.4</u>** – This section is being clarified by adding "Dispatchable Asset Related Demand" as a type of resource for which Forward Reserve Qualifying Megawatts are calculated. Further, the Tariff is being clarified by changing the word "by" to "for", and by deleting the word "Resource" from the end of Dispatchable Asset Related Demand."

- **<u>Section III.9.6.5</u>** – The Tariff is being clarified by adding the word "generating" after the term "off-line." In Section III.9.6.5(c) the words "in megawatts" are being deleted since the subject of the sentence is "Forward Reserve Delivered Megawatts."

- **<u>Section III.9.7.2(a)</u> –** This section is being clarified by applying terminology more appropriate for Demand Response Resources. For example, the phrase "Demand Response Resources that are not dispatched" is being added where "off-line Forward Reserve Resources" are referenced, and "Demand Response

Resources that have been dispatched" is being added where "on-line Forward Reserve Resources" are referenced. Further, context requires other wording and punctuation changes to provide further clarity in this section.

- **<u>Section III.9.7.3</u> –** An unnecessary reference to the ISO New England Manuals is being removed and the word "asset" is being changed to the defined term "Resource."

- **<u>Section III.10.1.1</u> –** The adjustment to the Real-Time Reserve Designation of a Resource used in the settlement process is being clarified. For example, the difference between the estimated capability of a Resource based on telemetry data, which is used to designate a Resource to provide Real-Time Operating Reserve, and its actual capability based on revenue quality meter data, could result in a downward adjustment to the Resource's Real-Time Reserve Designation MW used in settlement. For example, if a Resource (i.e., Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource) was designated in Real-Time to provide 5 MW of Operating Reserve, but after-the-fact revenue quality meter data showed that the Resource was only capable of providing 4 MW, then the Resource's Real-Time Reserve Designation MW used in settlement would be adjusted downward to 4 MW.

- **<u>Section III.10.3</u>** – The Tariff is being clarified by deleting the word "as" from the first sentence.

- **<u>Section III.13.1</u> –** The word "Section" is being added before a Tariff section reference.

- **<u>Section III.13.1.4.1.1</u>** – Reference is made to obsolete demand response programs and to an obsolete version of Section III.E (i.e., "Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program, as defined in Appendix E of this Market Rule 1.") The ISO proposes to eliminate this obsolete language.

- **<u>Section III.13.1.4.3 and Section III.E2.1.1</u> –** The requirement that prohibits Generator Assets and Demand Response Assets from being located at the same Retail Delivery Point, which could result in double-counting of any Net Supply, is being clarified and moved to Section III.E2.1.1. No substantive change to these requirements is being proposed. Section III.E2.1.1 addresses the rules governing the registration of Demand Response Assets so it is appropriate to move all Demand Response Asset registration requirements from Section III.13.1.4.3 to Section III.E2.1.1.

- **<u>Section III.13.1.4.3.2</u> –** The computation of a Real-Time Emergency Generation Resource's Demand Reduction Value for the period commencing

June 1, 2017 is being clarified. If a Real-Time Emergency Generation Asset is metered at the generator, the Average Hourly Output of that asset is used in the computation of the associated Real-Time Emergency Generation Resource's Demand Reduction Value. If a Real-Time Emergency Generation Asset is metered at the Retail Delivery Point, the Average Hourly Load Reduction of that asset is used in the computation of the associated Real-Time Emergency Generation Resource's Demand Reduction Value.

- **<u>Section III.13.5.3.2.3</u> –** This section is being clarified so that the capacity being assigned from a Supplemental Capacity Resource does not exceed the difference between (1) the sum of the Supplemental Capacity Resource's Real-Time Reserve Designations of TMNSR, TMSR and TMOR, and (2) its Capacity Supply Obligation. In contrast to a generator, a Demand Response Resource that is consuming energy from the electric grid (and does not have controllable behind-the-meter generation) can provide TMSR from a not dispatched state. Any TMSR provided by a Demand Response Resource ought to be considered in the Supplemental Capacity Resource assignment process.

- **<u>Section III.13.6.1.5.4.2</u> –** An incomplete Tariff section reference is being corrected.

- **<u>Section III.13.6.2.5.1</u>** – A reference to Appendix E is being changed to Appendix E1.

- **Section <u>III.13.7.1.5.10.1(e)</u> –** The word "and" is unnecessary and confusing, and is being deleted.

- **<u>Sections III.13.7.1.5.10.1(a), (e), and (f); and Sections III.13.7.1.5.10.2(b)(i) and (ii)</u> –** These sections are each clarified to better indicate "the lesser of" a series of values, which would be used in the Hourly Availability MW and the Availability Adjustment of a Demand Response Resource. The Hourly Available MW of a Demand Response Resource that is not dispatched, but is available for dispatch, is determined as "the lesser of" several values. In eliminating Net Supply Generator Assets and incorporating the Net Supply into the performance of Demand Response Assets, which in turn contributes to the performance of Demand Response Resources, the comparison of the values used to determine a resource's Hourly Availability MW and the Availability Adjustment became unclear. These changes restore the original intent of these sections of the Tariff.

- **<u>III.13.7.1.5.10.2</u> –** This section is being corrected wherever the demand reduction of a Demand Response Asset is associated with a recent seasonal audit of a Demand Response Capacity Resource. Seasonal audits are conducted on Demand Response Resources not Demand Response Capacity Resources. Also, the word "as" is being corrected to "has."

- **<u>Section III.13.7.2.5.4.1</u>** – An incomplete Tariff section reference is being corrected.

- **<u>Section III.E2.1.3</u> –** The word "consumption" is being replaced with the more appropriate term "demand reduction capability." At the end of this section, the word "retail" is being capitalized.

- **<u>Section III.E2.1.5</u> –** The word "that" is being corrected to "than."

- **<u>Section III.E2.2.2</u> –** The phrase "dispatch instructions from the ISO" is being replaced by the defined term "Dispatch Instructions."

- **<u>Section III.E2.3</u> –** The phrase "demand reduction payment" is being replaced by "payment for a demand reduction." $1000/MWh, which is the current Energy Offer Cap, is being replaced by the defined term "Energy Offer Cap."

- **<u>Section III.E2.5</u>** – This section is being simplified by deleting language related to the scheduling and dispatching of Demand Response Resources in the energy markets. The manner in which all Resources are presently scheduled and dispatched in the energy markets is addressed in Sections III.1.10.1A and III.1.10.2. Demand Response Resources and their respective Demand Reduction Offers have been integrated into Sections III.1.10.1A and III.1.10.2.

- **<u>Section III.E2.7.1</u>** – A missing "," is being added.

IV. CONCLUSION

Q: Does this conclude this testimony?

A: Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on October 30, 2014

Henry Y. Yoshimura

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