



July 27, 2017

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. ER17-__-000;
Revisions to Implement Full Integration of Demand Response**

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act,¹ ISO New England Inc. (the “ISO”), joined by the New England Power Pool (“NEPOOL”) Participants Committee (together, the “Filing Parties”),² hereby submit this transmittal letter and revisions to the ISO New England Inc. Transmission, Markets and Services Tariff (the “Tariff”) to fully integrate Price Responsive Demand into New England’s wholesale electricity markets (the “PRD Revisions”).³ As more fully described in Section IV of this filing letter and in the attached Testimony of Henry Y. Yoshimura, Director of Demand Resource Strategy at the ISO (the “Yoshimura Testimony,” sponsored solely by the ISO), the PRD Revisions are the final large package of Tariff revisions required to implement the full integration of demand response into New England’s Energy, Ancillary Services, and capacity markets on June 1, 2018.

¹ 16 U.S.C. § 824d (2012).

² Under New England's RTO arrangements, the ISO has the rights to make this filing of changes to the Tariff under Section 205 of the Federal Power Act. 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.

³ Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the Tariff, the Second Restated New England Power Pool Agreement, and the Participants Agreement.

I. REQUESTED EFFECTIVE DATE

The Filing Parties respectfully request that the Federal Energy Regulatory Commission (the “Commission”) accept the Tariff revisions filed herein without modification, condition, or delay, to be effective June 1, 2018, the previously approved effective date of the full integration of Price Responsive Demand into New England’s wholesale electricity markets.⁴

II. 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 460 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,⁵ 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.”

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

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⁴ See *ISO New England Inc. and New England Power Pool*, Docket Nos. ER16-167-000 and ER16-167-001 (Dec. 23, 2015) (delegated letter order accepting delay of full integration of demand response into the wholesale markets by one year, until June 1, 2018).

⁵ See *ISO New England Inc., et al.*, 109 FERC ¶ 61,147 (2004).

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III. STANDARD OF REVIEW

These changes are being submitted pursuant to Section 205, which “gives a utility the right to file rates and terms for services rendered with its assets.”⁷ Under Section 205, the Commission “plays ‘an essentially passive and reactive role’”⁸ whereby it “can reject [a filing] only if it finds that the changes proposed by the public utility are not ‘just and reasonable.’”⁹ 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.”¹⁰ The changes proposed herein “need not be the only reasonable methodology, or even the most accurate.”¹¹ As a result, even if an intervenor or the

⁶ 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.

⁷ *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002).

⁸ *Id.* at 10 (quoting *City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

⁹ *Id.* at 9.

¹⁰ *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

¹¹ *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

Commission develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.¹²

IV. EXPLANATION OF CHANGES

With this filing, the ISO and NEPOOL are submitting Tariff revisions necessary to fully integrate demand response into New England's wholesale electricity markets beginning on June 1, 2018. This set of revisions is the last in a series of changes that began with the ISO's Order No. 745¹³ compliance filing.¹⁴

The overarching full integration market design and many of the associated Tariff revisions have been submitted over the course of a number of years and accepted by the Commission in multiple orders.¹⁵ This package of changes addresses a number of outstanding issues. As Mr. Yoshimura explains in his testimony, in some cases, the PRD Revisions incorporate demand response into market mechanisms that deliberately had not included demand response due to uncertainty surrounding the Commission's jurisdiction (for example, the Energy Market offer flexibility revisions were developed and filed without consideration of demand response).¹⁶ In other cases, the PRD Revisions address details not specifically addressed in prior demand response integration filings (for example, the auditing process for Demand Response Resources). Still other changes result from the reorganization of existing Tariff language. For example, the PRD Revisions incorporate Appendix E2, currently a separate appendix containing

¹² 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*)).

¹³ *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 134 FERC ¶ 61,187 (2011), *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011).

¹⁴ *ISO New England Inc.*, Docket No. ER11-4336-000, Order No. 745 Compliance Filing (August 19, 2011).

¹⁵ The full participation of Demand Response Resources in the Day-Ahead and Real-Time Energy Markets is the second stage of a two-stage implementation process, which was filed by the ISO to comply with Order No. 745. The Commission largely accepted the ISO's proposal in the following orders: *ISO New England Inc.*, 138 FERC ¶ 61,042 (2012) (order on the ISO's Order No. 745 Compliance Filing); *ISO New England Inc. and New England Power Pool*, Docket No. ER12-947-000 (April 17, 2012) (delegated letter order accepting the ISO's Demand Response FCM Conforming Changes); *ISO New England Inc. and New England Power Pool*, Docket No. ER12-1550-000 (May 29, 2012) (delegated letter order accepting the ISO's Market Rule 1 Clarifications to the Transition Period Rules for Demand Response); *ISO New England Inc.*, 142 FERC ¶ 61,027 (2013) (order on the ISO's Market Rule 1 Demand Response FCM Conforming Changes for Full Integration); and *ISO New England Inc.*, 144 FERC ¶ 61,140 (2013) (order on the ISO's Market Rule 1 Clarifications to the Full Integration Rules for Demand Response and Revisions to Address the Treatment of Net Supply).

¹⁶ Yoshimura Testimony at 3-4.

a major share of Demand Response Resource rules, into the main body of Market Rule 1.¹⁷ The integration of the Demand Response Resource rules into the principal Tariff sections governing the Energy Market allows for the elimination of Appendix E in its entirety. Finally, the PRD Revisions include many smaller clarifying and remedial changes.¹⁸

The purpose of demand response full integration is to integrate demand response into New England's existing wholesale market structures in a manner comparable to other resources. As the Yoshimura Testimony explains, full integration encompasses three broad categories of changes, which allow Demand Response Resources to:¹⁹

(1) Participate directly in the Day-Ahead and Real-Time Energy Markets along with other energy resources. Integration is accomplished by enabling Demand Response Resources to submit Demand Reduction Offers into the Day-Ahead and Real-Time Energy Markets, which will be used to optimally commit and dispatch Demand Response Resources in conjunction with Generator Assets and all other energy resources. Demand Response Resources can be thought of as providing energy to the Energy Market in the form of demand reductions.

*(2) Provide Operating Reserve and participate directly in the Forward Reserve Market.*²⁰ Once Demand Response Resources are integrated into the Energy Market, Demand Reduction Offers in conjunction with all other Energy Market supply offers will be used to co-optimally dispatch and designate Resources to provide energy and Operating Reserve so as to produce the most economically efficient outcome to meet both energy and reserve requirements. Expanding the potential for additional resources to supply comparable energy and Operating Reserve services in Real-Time and on a forward basis through the Forward Reserve Market can provide for a more reliable electric system and increase competition among the suppliers of those services.

*(3) Receive obligations and compensation in the Forward Capacity Market that are fully comparable with those of other dispatchable resources.*²¹ With the integration of Demand Response Resources into the energy and reserves markets, all dispatchable resources participating in the capacity market, including Demand Response Resources, can receive fully

¹⁷ Section III of the Tariff is also referred to as Market Rule 1.

¹⁸ Yoshimura Testimony at 4.

¹⁹ Yoshimura Testimony at 4-5.

²⁰ The Commission accepted the ISO's Tariff revisions to fully integrate Demand Response Resources into the reserve markets in *ISO New England Inc. and New England Power Pool*, 150 FERC ¶ 61,007 (2015).

²¹ The Commission accepted the ISO's Tariff revisions to conform the Forward Capacity Market rules with the rules providing for full integration of Demand Response Resources into the wholesale markets in the following orders: *ISO New England Inc.*, 142 FERC ¶ 61,027 (2013) (as corrected by errata notice issued January 15, 2013); and *ISO New England Inc.*, 146 FERC ¶ 61,175 (2014).

comparable Forward Capacity Market obligations and compensation, reducing potential market distortion.

The Tariff revisions necessary to fully accomplish these three broad categories of changes are described below. Specifically, this transmittal letter describes revisions related to Demand Response Resources and: (A) Energy Market offers and price formation; (B) Energy Market settlement; (C) the provision of spinning reserves; (D) auditing to determine the ability to provide energy and non-spinning reserves; (E) the Forward Capacity Market; (F) the Market Monitoring provisions of Appendix A; (G) the Net Commitment Period Compensation provisions of Appendix F; and (H) miscellaneous and clean-up revisions.

Before discussing the specifics of these PRD Revisions, a brief review of the mechanics of demand resource participation in the Energy Market may be helpful. Under both the previously accepted full integration rules and under these revisions, a Demand Response Resource consists of one or more Demand Response Assets, which are the customer facilities that produce demand reductions. The performance of a Demand Response Resource during a dispatch equals the combined performances of its constituent Demand Response Assets during the dispatch. The performance of a Demand Response Asset is calculated by subtracting its metered consumption in an interval from its adjusted Demand Response Baseline in the same interval. The Demand Response Baseline (under the revisions and under the existing Tariff) is calculated based on the Demand Response Asset's average consumption over a number of previous days (in most cases, 10 previous days), and the *adjusted* Demand Response Baseline takes into account the Demand Response Asset's consumption immediately prior to dispatch.

A. Energy Market – Offers and Price Formation

Under the currently accepted full integration rules, Demand Response Resources are to submit Demand Reduction Offers (the analogue to Supply Offers submitted by generators) into the Day-Ahead and Real-Time Energy Markets. The PRD Revisions move the Tariff language describing Demand Reduction Offers from Appendix E into the main body of Market Rule 1, and in the process extend the Tariff's offer flexibility provisions to Demand Response Resources. The PRD Revisions place limits on the application of offer flexibility to Demand Response Resources so as to prohibit what would amount to self-scheduling. The revisions also define a new pricing location for Demand Response Resources; make a small change to the Demand Reduction Threshold Price rules; and integrate Demand Response Resources into the existing Rapid Response Pricing Asset Tariff provisions. These changes are described in more depth in the remainder of this Section IV.A.

1. Energy Market Offer Parameters and Energy Market Offer Flexibility

Demand Reduction Offers consist of a number of offer parameters analogous to the offer parameters specified in Supply Offers. (For example, while a Supply Offer specifies a Generator Asset's price/quantity pairs, Economic Min, Minimum Run Time, and Minimum Down Time, a

Demand Reduction Offer specifies a Demand Response Resource's price/demand reduction pairs, Minimum Reduction, Minimum Reduction Time, and Minimum Time Between Reductions, among other parameters.) The PRD Revisions integrate the rules governing Demand Reduction Offer parameters and requirements into the principal Tariff sections governing offers into the Day-Ahead and Real-Time Energy Markets. Specifically, language describing Demand Reduction Offers is moved from existing Sections III.E2.3 and III.E2.4 into revised Sections III.1.10.1A and III.1.10.9, and a prohibition on Demand Response Resource self-scheduling (discussed further in the Yoshimura Testimony and below in Section IV.A.2) is added to Sections III.1.10.3 and III.1.10.9. The PRD Revisions also make clarifying changes to a number of the Demand Reduction Offer parameter definitions, primarily so that the definitions parallel the analogous Supply Offer parameter definitions.

The PRD Revisions also incorporate Demand Reduction Offers into the new Energy Market offer flexibility paradigm. As discussed in the Yoshimura Testimony, in 2014, the ISO implemented energy market enhancements to provide greater flexibility to Market Participants to structure and modify their supply offers in the Day-Ahead and Real-Time Energy Markets.²² These changes allowed generators and Dispatchable Asset Related Demands ("DARDs") to (1) submit distinct hourly offers into the Day-Ahead and Real-Time Energy Markets and (2) update cost-related offer parameters within the Operating Day, up until 30 minutes prior to the hour in which the offer applies.²³ As Mr. Yoshimura explains,²⁴ when the offer flexibility rules were developed in 2013 and 2014, Demand Reduction Offers were not included in the project's scope because it was not clear that the Commission would maintain jurisdiction over demand response.²⁵ Now that jurisdiction is settled,²⁶ the PRD Revisions extend the offer flexibility provisions to the offers of Demand Response Resources, except where such flexibility conflicts with the self-scheduling prohibition that was previously accepted by the Commission.²⁷ (The following section, IV.A.2, discusses the self-scheduling exceptions.) The PRD Revisions allow Demand Response Resources to submit hourly price/demand reduction quantity offers, and to update those offers during the Re-Offer Period for the Operating Day. The extension of offer flexibility to Demand Response Resources flows naturally from the integration of Demand Reduction Offers into the existing hourly scheduling language in Section III.1.10.9, because the existing language provides for offer flexibility.

²² See *ISO New England Inc.*, 147 FERC ¶ 61,073 (2014) (order accepting the ISO's offer flexibility compliance filing).

²³ Yoshimura Testimony at 10.

²⁴ Yoshimura Testimony at 3-4.

²⁵ See *ISO New England Inc. and New England Power Pool*, Docket No. ER13-1877-000, Energy Market Offer Flexibility Changes (July 1, 2013). See also *ISO New England Inc. and New England Power Pool*, Docket No. ER13-1877-001, Compliance Filing (January 7, 2014).

²⁶ See *Federal Energy Regulatory Commission v. Electric Power Supply Association*, 136 S. Ct. 760 (2016).

²⁷ See *ISO New England Inc.*, 138 FERC ¶ 61,042 (2012) (order on the ISO's Order No. 745 Compliance Filing) at PP 112-113.

The Tariff changes associated with Demand Reduction Offers and the extension of energy market offer flexibility to Demand Response Resources are summarized in the table below.

Demand Response Resource Energy Market Offers and Energy Market Offer Flexibility	
Language Reference	Explanation
I.2.2	Clarifies definitions of the following offer parameters: Demand Response Resource Notification Time, Demand Response Resource Start-Up Time, and Minimum Time Between Reductions; makes revisions for clarity and to make parallel to analogous parameters of Generator Assets and DARDs
I.2.2	Adds Demand Response Resource interruptions to the definition of Maximum Number of Daily Starts
Deleted: III.E2.3	Deletes Day-Ahead Energy Market Demand Reduction Offers from III.E2 because the relevant provisions have been incorporated into III.1.10.1A
Deleted: III.E2.4	Deletes Real-Time Energy Market Demand Reduction Offers from III.E2 because the relevant provisions have been incorporated into III.1.10.9
III.1.10.1A	Integrates Day-Ahead Energy Market Offer information from III.E2 into the Tariff where Day-Ahead Scheduling is described; adds new section headings for clarity; describes Demand Response Resource offer parameters and offer requirements
III.1.10.3	Adds the restriction to the Tariff section describing Self-Scheduled Resources that Demand Response Resources shall not be Self-Scheduled
III.1.10.9	Integrates Real-Time Demand Reduction Offers into the area of the Tariff that describes Real-Time Offers and Bids; details offer parameter rules following the initial Reserve Adequacy Analysis that restrict Demand Response Resources from effectively self-scheduling; restates that Demand Response Resources cannot request to self-schedule

2. Restrictions on Offer Flexibility to Prevent Effective Self-Scheduling

As noted above, the ISO has filed, and the Commission has accepted, a prohibition on self-scheduling by Demand Response Resources on the grounds that, for purposes of Order No. 745, demand response must be committed and dispatched by the ISO, and a self-scheduled resource (by definition) is not.²⁸ The PRD Revisions make no change to this prohibition other

²⁸ See *ISO New England Inc.*, 138 FERC ¶ 61,042 (2012) (order on the ISO's Order No. 745 Compliance Filing) at PP 112-114.

than moving the implementing Tariff language (in revised form) from Sections III.E2.3 and III.E2.4 to Sections III.1.10.3 and III.1.10.9.

However, for reasons discussed below and in the Yoshimura Testimony, there are several financial and intertemporal offer parameters that, if changed by Demand Response Resources during the Operating Day, would effectively result in a self-schedule. These offer parameters are: price/demand reduction pairs, Interruption Cost, Demand Response Resource Notification Time, Demand Response Resource Start-Up Time, Minimum Reduction Time, and Minimum Time Between Reductions.²⁹ As such, the PRD Revisions do not allow Demand Response Resources to change these offer parameters after the initial Reserve Adequacy Analysis for the relevant Operating Day.

The offer parameters at issue can be classified as either financial parameters (offer price and Interruption Cost) or intertemporal parameters (the four other parameters mentioned above, all of which relate to time). Financial parameter changes and intertemporal parameter changes can result in effective self-scheduling in somewhat different ways, as described below and in the Yoshimura Testimony.³⁰

First, financial parameters: Demand Response Resources should only be paid for reducing demand if the reduction would not have been made in the normal course of business. Paying a Demand Response Resource to reduce demand if it would have reduced demand anyway, in the absence of payment, only raises costs and produces no incremental benefit.³¹ If allowed, a Demand Response Resource could strategically lower its offer prices and/or Interruption Costs during the Operating Day whenever it knew that its consumption in an upcoming interval was to be below average, so that it would receive a Dispatch Instruction to reduce (which it would have done anyway) and a corresponding energy payment. This would amount to self-scheduling. Accordingly, the PRD Revisions do not allow Demand Response Resources to change offer prices or Interruption Costs after the initial Reserve Adequacy Analysis for the Operating Day.³²

Second, intertemporal parameters: Allowing Demand Response Resources to change intertemporal parameters (Minimum Reduction Time, Minimum Time Between Reductions, Demand Response Resource Notification Time, or Demand Response Resource Start-Up Time) during the Operating Day also provides an opportunity for what amounts to self-scheduling. For example, a Demand Response Resource that has been committed or dispatched could increase its period of dispatch simply by increasing its Minimum Reduction Time during its commitment. Alternatively, a Demand Response Resource that the ISO had committed to reduce demand twice during an Operating Day (for example, from 10:00-12:00 and again from 14:00-16:00) could

²⁹ Yoshimura Testimony at 10-11.

³⁰ Yoshimura Testimony at 11-13.

³¹ Yoshimura Testimony at 11.

³² Yoshimura Testimony at 12.

effectively self-schedule during the interim 12:00-14:00 period by increasing its Minimum Time Between Reductions (or by changing the sum of its Demand Response Resource Notification Time and Demand Response Resource Start-Up Time) to a period greater than two hours. With a Minimum Time Between Reductions (or a combined notification and start-up time) of over two hours, the only way the ISO could bring the resource back by 14:00 (the beginning of the second commitment) would be to keep the unit on between the two periods.³³ In this way, by changing its intertemporal offer parameters during the Operating Day, the Demand Response Resource would have effectively self-scheduled for the period from 12:00 to 14:00. Accordingly, the PRD Revisions do not allow a Demand Response Resource to change the four above-mentioned intertemporal parameters after the close of the initial Reserve Adequacy Analysis.

The Tariff revisions that restrict offer flexibility where necessary to prevent effective self-scheduling are summarized in the table below.

Restrictions on Offer Flexibility to Prevent Effective Self-Scheduling	
Language Reference	Explanation
III.1.10.9	Integrates Real-Time Demand Reduction Offers into the area of the Tariff that describes Real-Time Offers and Bids; details offer parameter rules following the initial Reserve Adequacy Analysis that restrict Demand Response Resources from effectively self-scheduling; restates that Demand Response Resources cannot request to self-schedule

3. Defining a New Pricing Location for Demand Response Resources

Demand Response Resources are composed of one or more Demand Response Assets. Pursuant to existing Section III.E.1, where a Demand Response Resource consists of multiple Demand Response Assets, all such Assets must be located within the same Dispatch Zone – or, where a Dispatch Zone contains more than one Reserve Zone, all must be located within the same Dispatch Zone and Reserve Zone. The PRD Revisions introduce a new defined term, DRR Aggregation Zone, in place of the less precise and more cumbersome “same Dispatch Zone and Reserve Zone” used in the current Tariff.³⁴

As noted in the Yoshimura Testimony, under the previously filed and accepted full integration rules, a Demand Response Resource registered at a Dispatch Zone is paid the Locational Marginal Price (“LMP”) for the Dispatch Zone in which the resource is registered.³⁵ This means that while a Dispatch Zone can span more than one Reserve Zone (there is one such

³³ Yoshimura Testimony at 12-13.

³⁴ Yoshimura Testimony at 13.

³⁵ Yoshimura Testimony at 13.

Dispatch Zone today), only one LMP will be created for the entire Dispatch Zone. This is true even where congestion occurs across the Reserve Zone boundary or the reserve prices are different in the two Reserve Zones. Because of this, congestion that occurs between Reserve Zones is incorrectly reflected in a single, uniform Dispatch Zone LMP, and a Demand Response Resource could be compensated via local reserve pricing for a Reserve Zone in which it is not physically located. The PRD Revisions address this issue by creating separate and distinct pricing locations that coincide with the areas in which a Demand Response Resource's constituent Demand Response Assets can be located. As noted above, under the PRD Revisions, these areas are called DRR Aggregation Zones.

DRR Aggregation Zones provide appropriate energy and reserve pricing locations, so that any congestion that occurs at the Reserve Zone interface can be properly reflected in the DRR Aggregation Zone LMP, and so that Demand Response Resources can receive the Reserve Market Clearing Price for the Reserve Zone in which they are located.³⁶ This allows for the economic dispatch of Demand Response Resources that are located in Dispatch Zones that span multiple Reserve Zones, and for resources to be dispatched to maintain reserve requirements in each Reserve Zone.

As Mr. Yoshimura explains, at the present time, this change only impacts the Western Connecticut Dispatch Zone, which includes portions of both the Southwestern Connecticut Reserve Zone and the Connecticut Reserve Zone.³⁷ The Tariff changes associated with defining a new Demand Response Resource pricing location are summarized in the table below.

Price Formation and Dispatch For Demand Response Resources	
Language Reference	Explanation
I.2.2	Adds DRR Aggregation Zone to definition of Demand Response Resource; corrects section reference
I.2.2	Adds definition for DRR Aggregation Zone
I.2.2	Adds DRR Aggregation Zone to the definition of Location
I.2.2	Adds DRR Aggregation Zone to Locational Marginal Price (LMP) definition; deletes unnecessary language regarding the establishment of Dispatch Zone LMPs on and after June 1, 2018
III.2.1	Adds DRR Aggregation Zones to the list of Locations for which the ISO calculates an LMP
III.2.6	Adds Demand Reduction Offer to the rules for calculating Nodal Day-Ahead Prices
III.2.7	Replaces "Dispatch Zone" with "DRR Aggregation Zone"

³⁶ Yoshimura Testimony at 14.

³⁷ Yoshimura Testimony at 14.

4. Demand Reduction Threshold Price – the Offer Floor for Demand Response Resources

The Commission, in an order on the ISO’s Order No. 745 compliance filing, accepted revisions to the Tariff to establish a Demand Reduction Threshold Price (“DRTP”) to determine when it would be cost-effective to pay the LMP to demand response resources.³⁸ The PRD Revisions move the language describing the calculation of the DRTP from Section III.E2.6 to Section III.1.10.1.A(f). The DRTP is essentially an offer floor – all Demand Reduction Offers must be submitted at prices at or above the DRTP. The DRTP is recalculated monthly. As described below and in the Yoshimura Testimony, the PRD Revisions make one small change to the relationship between the DRTP and Demand Reduction Offers.³⁹

Under the existing Energy Market rules (as under the PRD Revisions), a Demand Reduction Offer submitted for an Operating Day will, like a Supply Offer, roll over into future Operating Days until replaced by a new offer. Under the existing rules, as Mr. Yoshimura describes in his testimony, if the DRTP increases from one month to the next, a Demand Reduction Offer that rolls over into a future month could end up being less than the DRTP. To address this possibility, the PRD Revisions require that the greater of the offer price or the DRTP be used in Day-Ahead Energy Market clearing and Real-Time Energy Market commitment, dispatch and pricing.⁴⁰ However, the ISO will continue using the offer price in any Net Commitment Period Compensation (“NCPC”) cost calculations because resources should not receive NCPC compensation to a level greater than their costs, which are expressed in the resource’s offer. (NCPC is discussed below in Section IV.G.)

The Tariff changes associated with the Demand Reduction Threshold Price are summarized in the table below.

Offer Floor Used in Clearing, Dispatching, and Pricing	
Language Reference	Explanation
Deleted: III.E2.6	Moves the determination of the Demand Reduction Threshold Price from III.E2 to III.1.10.1.A(f)
III.1.10.1A(e)(ii)	Considers any price specified below the Demand Reduction Threshold Price to be equal to the Demand Reduction Threshold Price for the Operating Day
III.1.10.1A(f)	Moves Demand Reduction Threshold Price from III.E2.6 to III.1.10.1.A(f); makes clarifying changes to Demand Reduction Threshold Price description

³⁸ See *ISO New England Inc.*, 138 FERC ¶ 61,042 (2012) at P 22.

³⁹ Yoshimura Testimony at 14-15.

⁴⁰ Yoshimura Testimony at 15.

5. Fast Start Pricing for Fast Start Demand Response Resources

The PRD Revisions also integrate Fast Start Demand Response Resources (an existing defined term) into the rules governing Rapid Response Pricing Assets so that Fast Start Demand Response Resources can set Real-Time Energy Market prices when they are the marginal resource. This requires that Fast Start Demand Response Resources meeting criteria comparable to that of other fast-start resources be included in the definition of Rapid Response Pricing Asset. Also, just as the Start-Up and No-Load Fees, Minimum Run Time, Economic Min, and Economic Max are used to establish the pricing adjustments for Rapid Response Pricing Assets that are Generator Assets, under the PRD Revisions, the comparable Demand Response Resource offer parameters – Interruption Cost, Minimum Reduction Time, Minimum Reduction, and Maximum Reduction – are used to establish the pricing adjustments for Rapid Response Pricing Assets that are Demand Response Resources.

The table below summarizes the Tariff changes associated with integrating Fast Start Demand Response Resources into the fast-start pricing rules.

Fast-Start Pricing	
Language Reference	Explanation
I.2.2	Incorporates Fast Start Demand Response Resources into definition of Rapid Response Pricing Asset
III.2.4	Adds Interruption Cost and Minimum Reduction Time to the energy offer adjustment for Rapid Response Pricing Assets
III.2.4(a)	Adds to paragraph (a) the appropriate adjustment to the Minimum Reduction of a Fast Start Demand Response Resource in order to parallel the adjustments for other resource types
III.2.4(d)	Adds a new paragraph addressing the inclusion of average Interruption Cost in the energy offer of a Fast Start Demand Response Resource in order to parallel adjustments for other resource types in (b) and revised (f)
III.2.4(e)	Adds a new paragraph addressing energy offer adjustment for Fast Start Demand Response Resources in order to parallel adjustments for other resource types in (c) and revised (g)

B. Energy Market – Settlement

As more fully described below, the PRD revisions make a number of changes related to Energy Market settlement. First, the revisions move the language describing Day-Ahead and Real-Time Energy Market settlement from existing Sections III.E2.7 and III.E2.9 into revised Section III.3.2.1. In so doing, the revisions extend sub-hourly settlement to Demand Response Resources. The revisions also incorporate Demand Response Resources into the existing term Metered Quantity For Settlement, extend an exemption from a cost allocation provision to all DARD Pumps, and, finally, allocate a share of inadvertent energy to Demand Response Resources.

1. Integrating Demand Response Resources into Day-Ahead Energy Market Settlement and Real-Time Energy Market Settlement

The PRD Revisions incorporate the existing Demand Response Resource settlement language, currently found in Sections III.E2.7 and III.E2.9, into Section III.3.2.1, where the existing settlement language for the Day-Ahead and Real-Time Energy Markets is located. In so doing, the concept of Day-Ahead Demand Reduction Obligations (defined as the MWhs of a Market Participant’s Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market in a single Location during a single settlement interval, increased by average avoided peak distribution losses) is incorporated into the Day-Ahead Energy Market settlement formulas, specifically into the calculation of the Day-Ahead Locational Adjusted Net Interchange, in a manner comparable to Day-Ahead Generation Obligations. Similar changes are made to relocate Real-Time Energy Market Settlement language from Appendix E2 into Section III.3.2.1, except that Real-Time Demand Reduction Obligations are excluded from the Real-Time Locational Adjusted Net Interchange Deviation. (This is because, as is discussed in the Yoshimura Testimony and in Section IV.B.4 below, Order No. 745 requires a separate accounting of Real-Time demand response costs.) In addition, several settlement-related definitions are clarified and one, Real-Time Demand Reduction Obligation Deviation, is created.

The revisions to Day-Ahead and Real-Time Energy Market settlement are summarized in the table below.

Integrating Demand Response Resources (“DRRs”) into Energy Market Settlement	
Language Reference	Explanation
I.2.2	Clarifies definition of Day-Ahead Demand Reduction Obligation
I.2.2	Clarifies definition of Real-Time Demand Reduction Obligation
I.2.2	Adds definition for Real-Time Demand Reduction Obligation Deviation
III.3.1	Removes obsolete reference to Appendix E2
III.3.2.1(a-p)	Adds section titles for clarity; adds Day-Ahead Demand Reduction Obligation; integrates Day-Ahead Demand Reduction Obligation into Day-Ahead Locational Adjusted Net Interchange Deviation and the Real-Time Locational Adjusted Net Interchange Deviation, clarifies that Real-Time Load Obligation is adjusted for unmetered load; incorporates requirements from III.E2; clarifies calculations for energy market settlement of Demand Response Resources
Deleted: III.E2.7; III.E2.9.1 through III.E2.9.3	Moves DRR settlement requirements into III.3.2.1

2. Integrating Demand Response Resources into Sub-Hourly Settlement

Under full integration, Demand Response Resources will be integrated into the Real-Time energy and reserve markets, which, as of earlier this year, are settled on a sub-hourly basis using five-minute “settlement intervals.”⁴¹ As with the offer flexibility rules discussed above, the sub-hourly settlement rules were written before it was clear that demand response would remain Commission jurisdictional; therefore, the sub-hourly settlement rules were drafted without reference to demand response settlement. With the Commission’s jurisdiction over demand response compensation confirmed, the computation of Real-Time Demand Reduction Obligations and Real-Time settlement for Demand Response Resources must now be modified to use five-minute settlement intervals instead of hourly integrated values. Sub-hourly settlement for Demand Response Resources is effectuated simply by integrating the settlement language for Demand Response Resources (currently in Appendix E2) into the existing settlement language of Section III.3.2.1 (as discussed above in Section IV.B.1), because existing Section III.3.2.1 uses the terminology “settlement interval” and stipulates that the settlement interval for the Real-Time Energy Market is five minutes.

The revisions required to extend sub-hourly settlement to Demand Response Resources are summarized in the table below.

Sub-Hourly Settlement	
Language Reference	Explanation
Deleted: III.E2.7	Moves language to III.3.2.1, in the process replacing “dispatch interval” with “settlement interval”
Deleted: III.E2.7.1	Moves language to III.3.2.1, in the process replacing “dispatch interval” with “settlement interval”
Deleted: III.E2.7.2	Moves language to III.3.2.1, in the process replacing “dispatch interval” with “settlement interval”
Deleted: III.E2.9.2	Moves language to III.3.2.1, in the process replacing “dispatch interval” with “settlement interval”

3. Real-Time Energy Market Settlement – Metered Quantity For Settlement

The term “Metered Quantity For Settlement” is used in the current Tariff in Real-Time Energy Market settlement and in determining NCPC credits (NCPC is discussed below in Section IV.G). Given the integration of Demand Response Resources into Energy Market settlement and their eligibility for NCPC, the PRD Revisions specify a Metered Quantity For Settlement for Demand Response Resources. This terminology update does not result in a

⁴¹ See *ISO New England Inc. and New England Power Pool*, Docket No. ER16-1838-000 (July 26, 2016) (delegated letter order accepting change in the settlement interval in the Real-Time energy and reserves markets from hourly to five-minute).

substantive change to settlement: the Metered Quantity For Settlement of a Demand Response Resource is defined as the sum of the demand reductions (generally the difference between the adjusted baseline and metered demand during a dispatch) provided by each Demand Response Asset constituting a Demand Response Resource, adjusted for average avoided peak distribution losses except for any portion representing Net Supply. The same concepts are found under the existing full integration rules (and in existing Section III.E2).

The Tariff changes related to Metered Quantity For Settlement are shown in the table below.

Real-Time Energy Market Settlement – Metered Quantity for Settlement	
Language Reference	Explanation
Deleted: III.E2.7	Moves Real Time Demand Reduction Obligation into III.3.2.1
Deleted: III.E2.9	Moves applicable Energy Market Settlement provisions to III.3.2.1
Deleted: III.E2.10	Moves treatment of average avoided peak distribution losses to applicable provisions of the Tariff
III.3.2.1.1	Clean up change moves sentences from the bottom to the top of the section to clarify that they apply to the whole section
III.3.2.1.1(b)	Excludes Demand Response Resources from Metered Quantity For Settlement calculation in this section
III.3.2.1.1(d)	Adds section defining how Metered Quantity for Settlement for Demand Response Resources is determined

4. Real-Time Energy Market Settlement – Order No. 745

In addition to moving the demand response Real-Time cost allocation rules from Section III.E2.93 into the main body of Market Rule 1, the PRD Revisions also make a small change to the existing Real-Time Energy Market Demand Response Resource settlement rules related to a requirement of Order No. 745.

By way of background, in Order No. 745, the Commission required that the costs associated with demand response compensation be allocated (billed) proportionally to all entities that purchase from the energy market in the areas and at the time demand resources are committed or dispatched.⁴² As noted in the Yoshimura Testimony, the ISO complied by allocating payments resulting from Real-Time demand reductions proportionally to Real-Time Load Obligation on a system-wide basis, excluding Real-Time Load Obligation incurred at

⁴² See *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 134 FERC ¶ 61,187 (2011) at P 102, *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011) at P 111.

External Nodes and by DARDs postured by the ISO.⁴³ (When the ISO postures a DARD Pump – that is, the load associated with the pumping phase of a pumped-storage hydroelectric facility – the resource will pump (even though it is not economic for it to do so) because the ISO believes that the hydroelectric generator associated with the DARD Pump will be needed to provide energy later in the day.)

Upon further consideration, the ISO plans to expand the DARD exclusion to all DARD Pumps, not just postured DARDs. Should Real-Time demand response costs be billed to DARD Pumps, the Supply Offers of the associated pumped-storage hydroelectric generators are likely to be higher to account for this cost, and/or the Demand Bids of the DARD Pumps are likely to be lower, either of which has the potential to distort the Real-Time Energy Market outcome, potentially raising the price or reducing the quantity of stored energy in future hours.⁴⁴

There is just one Tariff revision necessary to implement this change.

Real-Time Energy Market Settlement – Order No. 745	
Language Reference	
III.3.2.1(h)	Excludes all DARD Pumps (rather than postured DARDs) from allocation of Real-Time demand response charges and credits
Deleted: III.E2.9.3	Cost allocation language for demand response moved to III.3.2.1(h), exception expanded from postured DARDs to all DARD Pumps

5. Allocating a Share of Inadvertent Energy to Demand Response Resources

The final material Energy Market settlement-related revision relates to external transactions. Imbalances between scheduled external transactions and the actual energy flow across external tie lines can result in credits or charges that, under the current Tariff, are allocated pro-rata to Real-Time Generation Obligation and Real-Time Load Obligation. To treat Demand Response Resources comparably with other resource types, Real-Time Demand Reduction Obligation should be included in the allocation of inadvertent energy credits/charges in a manner parallel to the allocation of credits/charges to Real-Time Generation Obligation and Real-Time Load Obligation.

There is just one Tariff revision necessary to implement this change.

⁴³ See *ISO New England Inc.*, Docket No. ER11-4336-000, Order No. 745 Compliance Filing (Part 1 of 2) (August 19, 2011), pp. 5-6. *ISO New England Inc.*, 138 FERC ¶ 61,042 (2012) (order on the ISO's Order No. 745 Compliance Filing) at PP 37, 42.

⁴⁴ Yoshimura Testimony at 24-25.

Allocating a Share of Inadvertent Energy to Demand Response Resources	
Language Reference	Explanation
III.3.2.1(p)	Adds Real-Time Demand Reduction Obligations to the inadvertent energy calculation

C. Reserves

The PRD Revisions make two changes that are solely related to the provision of Operating Reserve, specifically, to: (1) the provision of Ten-Minute Spinning Reserve by Demand Response Resources and (2) reserve designation and credit.

1. Demand Response Resources and Ten-Minute Spinning Reserve

Under the current full integration rules, all Demand Response Resources with one-minute telemetry and without any controllable behind-the-meter generation are eligible to provide Ten-Minute Spinning Reserve (“TMSR”), even if they have not been dispatched. As Mr. Yoshimura describes in his testimony, this means that, under the current rules, a Demand Response Resource that has not received a Dispatch Instruction and has not completed its Demand Response Resource Notification Time and Demand Response Resource Start-Up Time can provide Ten-Minute Spinning Reserve.⁴⁵ In contrast, only a Generator Asset that is online (having received a Dispatch Instruction, completed its Notification Time, closed its breaker, completed its Start-Up Time and reached operation at least at its Economic Min) is eligible to provide Ten-Minute Spinning Reserve.

The initial rationale for this distinction was that only *online* Generator Assets are synchronized with the grid, whereas Demand Response Resources, because they are load, are always synchronized with the grid. However, on further review, the ISO has determined that the inconsistency between the treatment of Demand Response Resources and generators is not justified.⁴⁶

Ten-Minute Spinning Reserves are the highest quality reserves available in New England because the resources that provide them are already on dispatch, operating at least at their Economic Min (or Minimum Consumption Limit, in the case of DARDs). The current rules do not allow offline generators to provide Ten-Minute Spinning Reserve because, among other things, offline generators are not synchronized with the grid and require a Dispatch Instruction and notification and start-up time before they can provide energy to the grid at their Economic Min (even if that notification plus start-up time is zero). Similarly, Demand Response Resources that have not been dispatched also require notification and start-up time prior to reducing their energy consumption from the grid at their Minimum Reduction (for this reason, the market design allows Demand Response Resources to specify a Demand Response Resource

⁴⁵ Yoshimura Testimony at 15-16.

⁴⁶ Yoshimura Testimony at 16.

Notification Time and a Demand Response Resource Start-Up Time in their Demand Reduction Offers). Therefore, a Demand Response Resource that has not been dispatched is analogous to an offline generator and should not be eligible to provide Ten-Minute Spinning Reserve.⁴⁷

Conversely, as explained in the Yoshimura Testimony, a Demand Response Resource that has been dispatched, has completed its notification and start-up times, and is reducing demand at its Minimum Reduction has demonstrated that it has received a Dispatch Instruction, and that the Demand Response Assets, consisting of customer facilities that produce the demand reduction, are responding to the instruction. Since both Generator Assets and Demand Response Resources that have been dispatched, and are responding to Dispatch Instructions, have completed their notification and start-up times and are operating at least at their minimum production or reduction levels, they should be treated comparably in the provision of Ten-Minute Spinning Reserve.⁴⁸

There is just one Tariff change required for this change.

Change to Definition of TMSR	
Affected Tariff Section	Explanation
I.2.2.	Adds “that has been dispatched” to the definition of TMSR

2. Reserve Designation and Credits

The PRD Revisions contain two sets of Tariff changes regarding reserve designation and credits. First, the Tariff sections governing Demand Reduction Offers and qualifying megawatts in the Forward Reserve Market are modified to clarify which provisions are applicable to Generator Assets, DARDs, and Demand Response Resources, and to eliminate obsolete Tariff references and incorrect language. Other related Tariff sections are modified for consistency.

Second, the Real-Time and Forward Reserve credit computations are modified to include the same average avoided peak distribution loss adjustment for Demand Response Resources as are included in the Energy Market. And consistent with the current Energy Market rules, the proportion of a Demand Response Resource’s expected performance attributable to Net Supply will not receive credit for average avoided peak distribution losses.

The following table summarizes the Tariff changes associated with reserve designation and credits.

⁴⁷ Yoshimura Testimony at 16-17.

⁴⁸ Yoshimura Testimony at 17.

Reserve Designation and Credits	
Language Reference	Explanation
III.9.6.1	Clarifies that the first paragraph applies to Generator Assets and DARDS only, and deletes an obsolete Tariff reference; deletes unnecessary and potentially confusing language from the second paragraph
III.9.6.4	Adds section titles; clean up changes
III.9.6.5	Clarifies language in subsection (h) that describes the portion of Demand Response Resource Forward Reserve Delivered Megawatts to be increased by average avoided peak distribution losses
III.9.7.2	Clarifies the portion of Demand Response Resource Target Activation Megawatts to be increased by average avoided peak distribution losses
III.10.2, (a), (b), (c)	References III.9.6.5(h) to determine portion of Real-Time reserve credits to increase by average avoided peak distribution losses; adjusts Real-Time Reserve Credits for average avoided peak distribution losses for TMSR, TMNSR, TMOR (respectively)
III.10.4.1	Clarifies that Net Supply is excluded from the distribution loss adjustment in the calculation of Forward Reserve Obligation Charge MW of Demand Response Resources

D. Demand Response Resource Audits

As discussed in the Yoshimura Testimony, because demand resources currently participate primarily in the Forward Capacity Market, the auditing rules for demand resources are currently found in the Forward Capacity Market rules, and the entities that are audited pursuant to these rules are demand *capacity* resources.⁴⁹ With the integration of Demand Response Resources into the energy and reserve markets, however, audits must be instituted to establish the capability of Demand Response Resources to provide energy and Operating Reserves. The PRD Revisions therefore establish two different types of audits for Demand Response Resources, parallel to those for Generator Assets: Claimed Capability Audits, to determine the resource’s ability to provide energy (by reducing consumption in response to a Dispatch Instruction); and CLAIM10 and CLAIM30 audits, to determine the resource’s ability to provide reserves from an undispached state.

Under the PRD Revisions, the audit value of an Active Demand Capacity Resource is the sum of the audit values of its constituent Demand Response Resources.⁵⁰ Because of this, there

⁴⁹ Yoshimura Testimony at 17-18.

⁵⁰ Yoshimura Testimony at 22.

is no longer need for a separate audit for Active Demand Capacity Resources (currently called Demand Response Capacity Resources). The elimination of these rules is discussed below in Section IV.E.6.

1. Demand Response Resource Claimed Capability Auditing

Just as a Claimed Capability Audit of a Generator Asset establishes the real power output capability of the generator, the Claimed Capability Audit of a Demand Response Resource establishes the resource's demand reduction capability. Claimed Capacity Audits provide the ISO with necessary information about the demonstrated capability of each resource providing energy into the Energy Market. As Mr. Yoshimura explains in his testimony, each summer and winter season during the Capability Demonstration Year, each Demand Response Resource will be required to conduct a Seasonal DR Audit, comparable to the Seasonal Claimed Capability Audit of a Generator Asset. The Capacity Demonstration Year is the period from September 1 through August 31, with the summer audit season defined as April through November, and the winter audit season defined as December through March. Each Seasonal DR Audit will be one hour in duration, the same audit duration provided for in the current Forward Capacity Market audit rules for demand resources.⁵¹

The auditing rules for Demand Response Resources will be analogous to those of Generator Assets. A Demand Response Resource can request that it be dispatched by the ISO in order to be audited, or can request that its performance during a qualifying dispatch serve as its Seasonal DR Audit. Demand Response Resources, like Generator Assets, are subject to ISO-Initiated Capability Audits of operational parameters; an ISO-Initiated Capability Audit also fulfills the Demand Response Resource seasonal audit requirement. Similar to Establish Claimed Capability Audits of Generator Assets, requested Seasonal DR Audits are unannounced, are performed within five business days of the request, and are conducted between 08:00-22:00 on Non-NERC holiday weekdays. When an audit is conducted, the Demand Response Resource is dispatched by the ISO, and the performance of each Demand Response Asset that is part of the Demand Response Resource is measured by taking the difference between each Asset's adjusted Demand Response Baseline and its metered demand during the duration of the audit. A Demand Response Resource's Seasonal DR Audit value is the sum of the most recent audit values of its constituent Assets for that season. A Demand Response Resource's Seasonal DR Audit value will change if Assets are added to or removed from the Demand Response Resource, or when the Demand Response Resource performs a new Seasonal DR Audit. Demand Response Resources that fail to audit in a season will be assigned a zero audit value.⁵²

The following table summarizes the Tariff changes associated with the introduction of Claimed Capability Audits for Demand Response Resources.

⁵¹ Yoshimura Testimony at 18-19.

⁵² Yoshimura Testimony at 19-20.

Claimed Capability Audits of Demand Response Resources	
Language Reference	Explanation
I.2.2	Adds Demand Response Resource demand reduction capability to definition of Claimed Capability Audit
I.2.2	Clarifies that the definition of Seasonal Claimed Capability Audits applies to Generator Assets
I.2.2	Corrects reference and clarifies language in Seasonal DR Audit definition
III.1.5.1.1	Adds Seasonal DR Audit as a type of audit
III.1.5.1.2	Clarifies that Establish Claimed Capability Audits are for Generator Assets and cleans up language for clarity and consistency
III.1.5.1.3	Clarifies that Seasonal Claimed Capability Audits may only be performed by Generator Assets; clean up changes
III.1.5.1.3.1	Adds section on Seasonal DR Audits and describes timeframe of the audit seasons, requirements for performance, how the audits are requested and conducted, evaluation of audit results, exceptions for forced or scheduled curtailments, grandfathering of audit values from prior regime, etc.
III.1.5.1.4	States that ISO-Initiated Claimed Capability Audits shall replace either summer or winter Seasonal DR Audit values, clarifies areas that only apply to Generator Assets, clarifies language specifying when the audit begins for DRRs, adds DRR duration required to table, etc.
III.1.5.2	Clarifies language for consistency

2. Demand Response Resource CLAIM10/CLAIM30 Auditing

As Mr. Yoshimura explains in his testimony, the ISO evaluates the ability of resources to provide Operating Reserve from an undischarged state by requiring that all resources wishing to do so conduct CLAIM10 and/or CLAIM30 audits; the PRD Revisions add Demand Response Resources to this existing Tariff structure.⁵³ Under the PRD Revisions, therefore, CLAIM10 and CLAIM30 audits establish the ability of a Demand Response Resource to reduce demand from an undischarged state after 10 and 30 minutes have elapsed following the issuance of a Dispatch Instruction. All Demand Response Resources will be evaluated for non-spinning Thirty-Minute Operating Reserve, while only Demand Response Resources that consist entirely of Demand Response Assets reporting one-minute telemetry (or less) will be evaluated for Ten-Minute Non-Spinning Reserve.

In a fashion analogous to Generator Assets, the demand reduction achieved by a Demand Response Resource at the 10- and 30-minute points after dispatch are used to establish the

⁵³ Yoshimura Testimony at 20.

Demand Response Resource’s CLAIM10 and CLAIM30 audit values, respectively. As with a Generator Asset, a Demand Response Resource will be able to request a CLAIM10 and/or CLAIM30 audit, and each unannounced fast-start dispatch will count towards its CLAIM10 and/or CLAIM30 calculation. And just as with generators, the CLAIM10 or CLAIM30 value is adjusted by a performance factor that increases or decreases the CLAIM10 or CLAIM30 value based on the weighted average performance of the Demand Response Resource during its previous 10 dispatches. As with Generator Assets, any dispatch in which a Demand Response Resource goes out of service within 60 minutes results in a zero score for that start in the performance factor calculation. In addition, each resource providing 10- or 30-minute non-spinning reserves must audit at least once every Forward Reserve Procurement Period.⁵⁴

Finally, a Demand Response Resource whose composition of Demand Response Assets changes dramatically, or that operates infrequently, may be subject to increased ISO-initiated CLAIM10/CLAIM30 auditing. (Generator Assets that operate infrequently may similarly be subject to increased ISO-initiated auditing).

The table below summarizes the Tariff changes associated with the introduction of CLAIM10/CLAIM30 audits for Demand Response Resources.

CLAIM10/CLAIM 30 Audits of Demand Response Resources	
Language Reference	Explanation
I.2.2	Adds section reference in definition of Summer Capability Period and Winter Capability Period
III.9.5.3.1(5)	Clarifies the dispatches that will not be included in CLAIM10 and CLAIM30 values, adds language regarding the ratio of certain Day-Ahead offer costs to Real-Time offer costs that would exclude a dispatch from the calculation of CLAIM10 and CLAIM30 values for a Demand Response Resource
III.9.5.3.1(6)(a), (b), (c)	Adds language grandfathering values from prior regime
III.9.5.3.2	Adds language to parallel a generator trip
III.9.5.3.4	Clean up change

E. Forward Capacity Market

While the revisions to the Forward Capacity Market rules (Section III.13 of the Tariff) are numerous, very few of them involve substantive changes. The Forward Capacity Market revisions are described below and include: nomenclature changes; section reorganization; the elimination, for some resources, of the obligation to submit Measurement and Verification Plans; a clarification of the participation of existing emergency generators as New Demand Capacity Resources; a clarification of the determination of Qualified Capacity for Demand Capacity

⁵⁴ Yoshimura Testimony at 21.

Resources; and the elimination of auditing rules applicable to Demand Capacity Resources composed of Demand Response Resources (that is, Active Demand Capacity Resources).

1. Nomenclature

As discussed in the Yoshimura Testimony, there are a number of changes to the terminology used in the Forward Capacity Market to describe resources that deliver capacity primarily by reducing demand.⁵⁵

First, to make the terminology describing different capacity resources consistent, the umbrella term “Demand Capacity Resource” replaces the umbrella term “Demand Resource.” (The term “Demand Capacity Resource” now parallels two other capacity market terms, “Generating Capacity Resource” and “Import Capacity Resource.”) Demand Capacity Resources can be one of three types (discussed further below): (1) Active Demand Capacity Resources, (2) On-Peak Demand Resources, and (3) Seasonal Peak Demand Resources.

The term Active Demand Capacity Resource is new to the PRD Revisions, replacing the term “Demand Response Capacity Resource.” This revision was made for clarity’s sake, because some found the prior terminology confusing. An Active Demand Capacity Resource consists of one or more Demand Response Resources. (As mentioned, Demand Response Resources are in turn composed of Demand Response Assets.) On-Peak Demand Resource and Seasonal Peak Demand Resources are composed of Assets and measures.

The existing Tariff uses the defined term Demand Reduction Value to describe both the projected demand reduction of a proposed resource for use in the qualification process, and the achieved demand reduction of an actual resource for use in the settlement process. Some found this dual meaning confusing. Under the already approved full integration rules, the concept of a Demand Reduction Value is no longer needed for energy market settlement, so this meaning is stricken from the Tariff. To further reduce confusion, where it is used in the qualification process, the defined term “Demand Reduction Value” is deleted and replaced with the plain English, undefined term “demand reduction value.”

In addition to Demand Reduction Value, there are a number of other capacity market terms that are no longer needed under full integration, including “Capacity Value,” “Audited Demand Reduction,” “Demand Resource Commercial Operation Audit,” “New Demand Response Asset,” “New Demand Response Asset Audit,” and “Net Supply Limit.” These terms are eliminated.

The Forward Capacity Market terminology changes are summarized in the following table.

⁵⁵ Yoshimura Testimony at 6-8.

Forward Capacity Market – Nomenclature Changes	
Language Reference	Explanation
I.2.2	Adds definition for Active Demand Capacity Resources, which replaces prior term, Demand Response Capacity Resources; deletes definition of Demand Response Capacity Resources
I.2.2	Clarifies Asset definition to include Demand Response Asset and components of On-Peak Demand Resources and Seasonal Peak Demand Resources
I.2.2	Deletes definition of Audited Demand Reduction because term is no longer used
I.2.2	Deletes definition of Capability Year because term is no longer used
I.2.2	Deletes definition of Capacity Value because term is no longer used
I.2.2	Deletes the defined term Demand Reduction Value because it is no longer used (note that the Tariff still refers to “demand reduction value” to refer to the demand reduction capability of a Demand Capacity Resource)
I.2.2	Changes defined term from “Demand Resource” to “Demand Capacity Resource;” clarifies definition of Demand Capacity Resource: notes that definition applies to Existing Demand Capacity Resources and New Demand Capacity Resources, updates Demand Capacity Resource types, removes obsolete reference to III.E2, removes details that are found elsewhere
I.2.2	Deletes definition of Demand Resource Commercial Operation Audit because term is no longer used (III.13.6.1.5.3(b) clarifies that any audit can be used to demonstrate commercial capacity)
I.2.2	Deletes definition of Load Response Program because term is no longer used
I.2.2	Deletes definition of Load Response Program Asset because term is no longer used
I.2.2	Deletes definition of Offered Full Reduction Time because term is no longer used
I.2.2	Deletes definition of Day-Ahead Load Response Program because term is no longer used
I.2.2	Deletes reference to Audited Full Reduction Time because term is no longer used
I.2.2	Deletes definition of Enrolling Participant because term is no longer used
I.2.2	Deletes definition of New Demand Response Asset and New Demand Response Asset Audit because these terms are not used

Forward Capacity Market – Nomenclature Changes	
Language Reference	Explanation
I.2.2	Deletes definition of Net Supply Limit because term is no longer used
I.2.2	Deletes definition of Percent of Total Demand Reduction Value Complete because term is no longer used
I.2.2	Changes term from “Demand Resources” to “Demand <i>Capacity</i> Resources” in the following definitions: Dynamic De-List Bid, Existing Demand Resource (now Existing Demand <i>Capacity</i> Resource), New Capacity Show of Interest Submission Window, New Demand Resource (now New Demand <i>Capacity</i> Resource), New Demand Resource Qualification Package (now New Demand <i>Capacity</i> Resource Qualification Package), New Demand Resource Show of Interest Form (now New Demand <i>Capacity</i> Resource Show of Interest Form), On-Peak Demand Resource, Retirement De-List Bid, Seasonal Peak Demand Resources, Existing Demand Capacity Resources, Dynamic De-list Bid, Existing Demand Resource, Project Sponsor, Seasonal Peak Demand Resource, Static De-List Bid, New Capacity Offer, Permanent De-list Bid
I.3.9.3	Changes section title and first sentence to reflect updated term, “Demand <i>Capacity</i> Resource”
III.13.1	Adds “Capacity” to Demand <i>Capacity</i> Resource; removes redundant sentence limiting a Generating Capacity Resource and a Demand Resource located at the same Retail Delivery Point from participating in the FCM because that information is stated in III.8.1.1
Deleted: existing III.13.1.4.1.3 through existing III.13.1.4.1.3.2.2	Removes language because the market rules no longer reference monthly or seasonal Demand Reduction Values
Deleted: existing III.13.1.4.3.2.1	Deletes Demand Reduction Values, which are no longer used to determine performance
Deleted: existing III.13.1.4.7 through existing III.13.1.4.7.2	Deletes Capacity Values, which term is no longer used
III.13.3.2.2	Replaces term “Demand Reduction Value” with “demand reduction value”; adds “Demand <i>Capacity</i> Resource”; updates section references; clean up changes
III.13.7.5.1	Replaces term “Demand Reduction Value” with “demand reduction value”; replaces “Demand Resource” with “Demand <i>Capacity</i> Resource”; cleans up language stating that a load-serving entity’s Capacity Requirement will not be reconstituted to include the demand reduction of Demand

Forward Capacity Market – Nomenclature Changes	
Language Reference	Explanation
	Capacity Resources or Demand Response Resources
III.13.1, III.13.1.1.1, III.13.1.1.1.7, III.13.1.1.2.9, III.13.1.2.1, III.13.1.2.2.5.2, III.13.1.4, III.13.1.4.1.1.5, III.13.1.4.1.1.2.7, III.13.1.4.3.1.3, III.13.1.5, III.13.1.7, III.13.1.9, III.13.2.3.2, III.13.2.5, III.13.2.7.7, III.13.3.2.2, III.13.4.2.1.2.1.4, III.13.6.1.5.1, III.13.1.1.1, III.13.1.2.1, III.13.6.3, III.13.7.1.2.1, III.13.1.9.3.1-III.13.3.2.1	Changes “Demand Resource” to “Demand <i>Capacity</i> Resource”
III.13.1.1.1.7, revised III.13.1.4, revised III.13.1.4.2.2, III.13.3.2.2(b)(ii)	Capitalizes “A” in Asset
Revised III.13.1.4.1.1.1, revised III.13.1.4.1.1.3, revised III.13.1.4.1.1.4, III.13.6.1.5.1, III.13.6.1.5.2, III.13.6.1.5.3, III.13.6.2.5.1, III.13.6.2.5.1.1, III.13.6.2.5.1.2, III.13.6.2.5.2, III.13.6.4, III.13.7.2.2	Changes “Demand Response Capacity Resource” to “ <i>Active</i> Demand Capacity Resources”

2. Organizing Demand Capacity Resource Forward Capacity Auction Qualification Provisions

Next, a large number of non-substantive, organizational changes are being made to the provisions describing the process by which Demand Capacity Resources qualify for Forward Capacity Auctions, which are found in Section III.13.1.4 of the Tariff. Section III.13.1 includes distinct qualification processes for New Capacity Resources and for Existing Capacity Resources. Within the Tariff sections describing the qualification processes for Generating Capacity Resources and Import Capacity Resources, the rules describing the qualification of New Capacity Resources precede the rules describing the qualification of Existing Capacity Resources. In contrast, under the existing Tariff, the rules describing the qualification processes of New and Existing Demand Capacity Resources are intermingled, with some sections containing information concerning both qualification processes. In an effort to bring more clarity

to the Tariff, the PRD Revisions organize the Demand Capacity Resource qualification sections so that the qualification process for New Demand Capacity Resource precedes the process for Existing Demand Capacity Resources. In addition, for clarity and consistency, several of the sections are rearranged so that information is presented in the same order as the parallel information is presented for Generating Capacity Resources.

The following table summarizes the Tariff changes required to properly organize the Demand Capacity Resource Forward Capacity Auction qualification language.

Forward Capacity Market – Qualification Language Reorganization	
Language Reference	Explanation
Existing III.13.1.4.1 becomes revised III.13.1.4	Adds description of Active Demand Capacity Resource, On-Peak Demand Resource and Seasonal Peak Demand Resource; reference to measure life relocated in revised form (to revised III.13.1.4.2); clean up changes
Deleted: existing III.13.1.4.1.1	Moves language down, substantively unchanged (to revised III.13.1.4.2, with de-list bid language to revised III.13.1.4.2.2), as part of section reordering so that qualification rules governing New Demand Capacity Resources precede qualification rules governing Existing Demand Capacity
Revised III.13.1.4.1	These revisions are addressed below in Section IV.E.4 of this transmittal letter
Revised III.13.1.4.1.1	Revisions to describe determination of FCA Qualified Capacity; to make clear the required submittals for Demand Capacity Resource qualification; to make clear that only On-Peak and Seasonal Peak Demand Resources must submit Measurement and Verification Plans
Deleted: existing III.13.1.4.1.5	Moves language down, substantively unchanged (to III.13.1.4.1.1.3), because language describing the ISO’s initial analysis should follow language describing the submission
Revised III.13.1.4.1.1.1	Clean up changes; includes language (from existing III.13.1.4.3.2) specifying that Active Demand Capacity Resource estimates must be consistent with the baseline methodology in III.8
Deleted: existing III.13.1.4.2.1	Moves language down as part of section reordering so that qualification rules governing New Demand Capacity Resources precede qualification rules governing Existing Demand Capacity; qualification process for Existing Demand Capacity Resources now found in revised Sections III.13.1.4.2, III.13.1.4.2.1, and III.13.1.4.2.2
Revised III.13.1.4.1.1.2 through revised III.13.1.4.1.1.2.7 and	Clarifying and clean up revisions to descriptions of New Demand Capacity Resource Qualification Package contents

Forward Capacity Market – Qualification Language Reorganization	
Language Reference	Explanation
revised III.13.1.4.1.1.2.7 and III.13.1.4.1.1.2.8	
Existing III.13.1.4.2.2.6 moved to revised III.13.1.4.1.1.2.8(b)	Deletes existing section and moves language down to III.13.1.4.1.1.2.8(b), substantively unchanged, as rationing election is part of offer information
Deleted: existing III.13.1.4.2.3	Moves language down to III.13.1.4.1.1.4, substantively unchanged, as consistency of Show of Interest submissions and qualification packages should follow the descriptions of both submittals
Revised III.13.1.4.1.1.3 and revised III.13.1.4.1.1.4	Relocates contents to here from existing III.13.1.4.1.5 and existing III.13.1.4.2.3, substantively unchanged, as ISO's initial analysis and consistency of submittals should follow submittal descriptions
Revised III.13.1.4.1.1.5	Clean up and clarifying revisions
Deleted: existing III.13.1.4.2.5.2	Moves language down to revised III.13.1.4.2.1, substantively unchanged, as part of section reordering so that qualification rules governing New Demand Capacity Resources precede qualification rules governing Existing Demand Capacity Resources
Existing III.13.1.4.2.5.3 through III.13.1.4.2.5.3.2 become revised III.13.1.4.1.1.6	Sections condensed into one for clarity, so that the Qualification Determination Notification is described in single section; prohibition on changing resource type during Capacity Commitment Period moved to revised III.13.1.4.2.1(c); addition of eight percent in revised III.13.1.4.1.1.6(a) discussed below in Section IV.E.5 of this transmittal letter
Revised III.13.1.4.2	Relocates material here, substantively unchanged, from existing III.13.1.4.1.1
Revised III.13.1.4.2.1 & III.13.1.4.2.2	Relocates material here from existing III.13.1.4.2.5.2, existing III.13.1.4.1.1 and existing III.13.1.4.2.1; clarifies that Qualified Capacity value includes gross up (by average avoided peak transmission and distribution losses)

3. Measurement and Verification Plans

Under the current Tariff, all Demand Resources (which, as mentioned, are referred to as Demand Capacity Resources under the PRD Revisions) must submit Measurement and Verification Plans during the Forward Capacity Auction qualification process. These plans provide details on how the performance of the demand resource will be determined, and what data needs to be submitted to verify that the asserted savings have been achieved.

However, as noted, under the PRD Revisions, the performance of Active Demand Capacity Resources is established based on the performance of their constituent Demand Response Resources (which, as is also noted, depends on the performance of their constituent Demand Response Assets).⁵⁶ In other words, under the existing full integration rules and under the PRD Revisions, the Tariff specifies how the performance of Active Demand Capacity Resources, Demand Response Resources, and Demand Response Assets is to be determined. As such, Active Demand Capacity Resources no longer need to submit Measurement and Verification Plans.

Because the PRD Revisions make no change to how performance is determined for On-Peak Demand Resources and Seasonal Peak Demand Resources, these capacity resources must continue to submit Measurement and Verification Plans. Accordingly, the PRD Revisions eliminate the existing measurement and verification rules, and the associated qualification rules, for Active Demand Capacity Resources, but retain them for On-Peak Demand Resources and Seasonal Peak Demand Resources.⁵⁷

The required Tariff changes are summarized below.

Forward Capacity Market – Measurement and Verification Plans	
Language Reference	Explanation
I.2.2	Clarifies that the definition of Measure Life applies to On-Peak and Seasonal Peak Demand Resources
I.2.2	Clarifies that the definition of Measurement and Verification Documents applies to On-Peak and Seasonal Peak Demand Resources
I.2.2	Clarifies that the definition of Measurement and Verification Plan applies to On-Peak and Seasonal Peak Demand Resources
I.2.2	Clarifies that the definition of Measurement and Verification Reference Report applies to On-Peak and Seasonal Peak Demand Resources
I.2.2	Clarifies that the definition of Measurement and Verification Summary Report applies to On-Peak and Seasonal Peak Demand Resources
I.2.2	Clarifies that the definition of Updated Measurement Verification Plan applies to Seasonal Peak and On-Peak Demand Resources
Revised III.13.1.4.1.1	Revisions to make clear that only On-Peak or Seasonal Peak Demand Resources must submit a Measurement and Verification Plan
Revised III.13.1.4.1.1.5	Clarifies that the Measurement and Verification Plan compliance

⁵⁶ Yoshimura Testimony at 22.

⁵⁷ Yoshimura Testimony at 22.

Forward Capacity Market – Measurement and Verification Plans	
Language Reference	Explanation
	in (e) applies only to On-Peak and Seasonal Peak Demand Resources
III.13.1.4.3	Specifies that Measurement and Verification Plans apply only to Seasonal Peak and On-Peak Demand Resources; removes language applicable to Active Demand Capacity Resources (referred to as Demand Response Capacity Resources)
III.13.1.4.3.1 through III.13.1.4.3.1.4	Revises sections to clarify that Measurement and Verification Plans submitted only by On-Peak and Seasonal Peak Demand Resources; clean up changes
Deleted: III.13.1.4.3.2	Moves content concerning On-Peak and Seasonal Peak Resources with distributed generation to final sentence of III.13.1.4.3.1; moves content describing baseline methodology contents to revised III.13.1.4.1.1.1; deletes remainder as redundant
Revised III.13.1.4.3.2	Adds “Lead Market Participant” to reflect that Existing resources submit Measurement and Verification Plans too
Deleted: III.13.1.4.3.4	Deletes because language is unnecessary, stated elsewhere

4. Existing Emergency Generators Participating as New Demand Capacity Resources

Under the current Tariff, Section III.13.1.4.1.2 allows an existing emergency generator to participate in the Forward Capacity Market as a Real-Time Emergency Generation Resource. However, as noted in the Yoshimura Testimony, the Commission recently accepted Tariff changes that remove Real-Time Emergency Generation Resources from the Forward Capacity Market as of June 1, 2018.⁵⁸ Therefore, the PRD Revisions modify existing Section III.13.1.4.1.2 by removing all of the existing language pertaining to emergency generators. The revisions also make clarifying changes to exclude existing demand-reducing measures from becoming part of a new On-Peak or Seasonal Peak Demand Resource. These changes are effected by revisions to one section.

Forward Capacity Market – Existing Emergency Generators Participating as New Capacity	
Language Reference	Explanation
Existing III.13.1.4.1.2 becomes revised III.13.1.4.1	Clarifies that existing demand-reducing measures cannot become part of a new On-Peak or Seasonal Peak Demand Resource; language pertaining to emergency generators deleted

⁵⁸ See *ISO New England Inc. and New England Power Pool Participants Committee*, Docket Nos. ER17-925-000 and ER17-925-001 (March 15, 2017) (delegated letter order accepting revisions to eliminate Real-Time Demand Response Resources and Real-Time Emergency Generation Resources).

5. Qualified Capacity for Demand Capacity Resources

Under the current Tariff, the Qualified Capacity of a New Demand Capacity Resource is established in existing Section III.13.1.4.1.4. Under the reorganization described above, the Qualified Capacity for a New Demand Capacity Resource is established in revised Section III.13.1.4.1.1.6(a). The revised language clarifies that, to determine the Qualified Capacity of a New Demand Capacity Resource, the ISO-determined demand reduction value is increased by average avoided peak transmission and distribution losses. The PRD Revisions furthermore state that those losses are equal to eight percent.

Under the current Tariff, Section III.13.7.2.2 refers to “multipl[ying] by 1.08” several times, which implies, but does not explicitly state, that transmission and distribution losses are equal to eight percent. Under the PRD Revisions, this fact is explicitly spelled out, as noted above, in Section III.13.1.4.1.1.6(a). Section III.13.7.2.2 is revised such that the relevant value is “increased by average avoided peak transmission and distribution losses” rather than being “multiplied by 1.08.” In this way, the references to transmission and distribution losses in Section III.13.7.2.2 are made consistent with other such references in Section III.13.

The following table summarizes these Tariff changes.

Forward Capacity Market – Demand Capacity Resource Qualified Capacity Determination	
Language Reference	Explanation
Revised III.13.1.4.1.1.6(a)	Describes Qualified Capacity for Demand Capacity Resources; explicitly states that average avoided peak transmission and distribution losses are equal to eight percent; clean up changes
III.13.7.2.2(c), (d), (f)	Clarifies that demand reduction MWhs (excluding Net Supply) are increased by “average avoided peak transmission and distribution losses,” rather than being “multiplied by 1.08”

6. Capacity Market Auditing Revisions

In the existing Tariff, the auditing rules for all Demand Capacity Resources – On-Peak Demand Resources, and Seasonal Peak Demand Resources and Active Demand Capacity Resources (which, as mentioned, are currently termed Demand Response Capacity Resources) – are found in the Forward Capacity Market section, Section III.13.

As mentioned above, under the PRD Revisions, there are no longer auditing rules explicitly for Active Demand Capacity Resources. Instead, under the revisions, the audit performance of an Active Demand Capacity Resource is the sum of the audit performances of its constituent Demand Response Resources.⁵⁹ The rules governing the audits of Demand Response

⁵⁹ Yoshimura Testimony at 22.

Resources, (as discussed above in Section IV.D), have been added to Sections III.1.5.1 and III.9.5.3. Therefore, the existing auditing rules for Active Demand Capacity Resources, currently located in Section III.13, are eliminated.

There are no similar changes made to the auditing rules for On-Peak Demand Resources or Seasonal Peak Demand Resources. Therefore, like the rules governing the submission of Measurement and Verification Plans, the existing auditing rules for On-Peak Demand Resources and Seasonal Peak Demand Resources must be retained. Under the current Tariff, however, the auditing rules for the three types of Demand Capacity Resources are intertwined, so the Tariff changes required to do this are numerous. The PRD Revisions also streamline the remaining language describing the audits of On-Peak Demand Resources and Seasonal Peak Demand Resources.

Finally, changes to auditing terminology require parallel language changes to provisions describing the determination of the Qualified Capacity value of Demand Capacity Resources for the third Annual Reconfiguration Auction. Specifically, under the PRD Revisions, the Seasonal DR Audit value and the Passive DR Audit value encompass the value that is called, under the current Tariff, the Demand Resource Commercial Operation Audit value. Therefore, the term Demand Resource Commercial Operation Audit can be eliminated from the Tariff, and references to that term in the third Annual Reconfiguration Auction rules (specifically, in Sections III.13.4.2.1.2.2.4.1 and III.13.4.2.1.2.2.4.2) can be eliminated as well.

The following table summarizes the Forward Capacity Market demand response auditing Tariff changes.

Forward Capacity Market – Auditing-Related Revisions	
Language Reference	Explanation
I.2.2	Deletes definition of Demand Resource Commercial Operation Audit because it is no longer used (any audit can be used to demonstrate commercial capacity, per III.13.6.1.5.3(b))
I.2.2	Removes definition of New Demand Response Asset Audit because this term is not used
I.2.2	Adds definition of Passive DR Audit
I.2.2	Replaces DR Auditing Period definition with Passive DR Auditing Period definition to reflect that it applies to On-Peak and Seasonal Peak Demand resources
I.2.2	Clarifies that the definition of Seasonal DR Audit is applicable to Demand Response Resources and updates section references; this audit is no longer a capacity market audit, and instead takes place as described in III.1.5.1
I.2.2	Clarifies that the definition of Seasonal Claimed Capability Audits applies to Generator Assets
III.1.7.12	Adds section describing how an Active Demand Capacity Resource’s Seasonal DR Audit value is calculated

Forward Capacity Market – Auditing-Related Revisions	
Language Reference	Explanation
III.13.4.2.1.2.2.4.1	Specifies Demand <i>Capacity</i> Resources; clarifies, for use in ARA 3 Qualified Capacity (“QC”) determination, the use of the summer Seasonal DR Audit value or summer Passive Audit Value in effect at the time of qualification for ARA 3 to determine the summer ARA QC of a Demand Capacity Resource
III.13.4.2.1.2.2.4.2	Specifies Demand <i>Capacity</i> Resources; clarifies, for use in ARA 3 QC determination, the use of the winter Seasonal DR Audit value or winter Passive Audit Value in effect at the time of qualification for ARA 3 to determine the winter ARA QC of a Demand Capacity Resource
III.13.6.1.5.3	Adds to (b) language describing audits to verify commercial capacity; adds to (c) language describing audit values of Active Demand Capacity Resources; clarifies in (d) auditing requirements for On-Peak and Seasonal Peak Resources (which are detailed in revised III.13.6.1.5.4)
III.13.6.1.5.4	Consolidates auditing requirements for On-Peak and Seasonal Peak Demand Resources (currently found in existing III.13.6.1.5.4 through existing III.13.6.1.5.4.8.1)
Deleted: III.13.6.1.5.4.1	Moves relevant subsections to revised III.13.6.1.5.4
Deleted: III.13.6.1.5.4.2	Moves applicable requirements to III.1.5
Deleted: III.13.6.1.5.4.3 Deleted: III.13.6.1.5.4.3.1 Deleted: III.13.6.1.5.4.3.2	Deletes as requirements applicable to Demand Response Resources moved to III.1.5; requirements applicable to On-Peak or Seasonal Peak Demand Resources retained in III.13.6.1.5.4
Deleted: III.13.6.1.5.4.3.3	Moves applicable requirements to III.1.5
Deleted: III.13.6.1.5.4.4	Deletes as any audit can be used to demonstrate commercial capacity (per III.13.6.1.5.3(b))
Deleted: III.13.6.1.5.4.5	Deletes as language is unnecessary
Revised III.13.6.1.5.5	Clarifies and updates language for Level 1 & Level 2 Audits; makes clear that such audits can be of any component (Asset or measure) of any Demand Capacity Resource
Deleted: III.13.6.1.5.4.6 Deleted: III.13.6.1.5.4.7 Deleted: III.13.6.1.5.4.8 Deleted: III.13.6.1.5.4.8.1	Moves requirements applicable to Demand Response Resources to III.1.5; requirements applicable to On-Peak or Seasonal Peak Demand Resources retained in III.13.6.1.5.4

F. Market Rule 1, Appendix A – Market Monitoring, Reporting and Market Power Mitigation

The PRD Revisions make no changes to the Internal Market Monitor’s approach to monitoring Demand Reduction Offers; therefore, no substantive changes are being made to

Appendix A. There are several non-substantive changes being made, however, including the two discussed below.

First, in Section III.A.10, the term “Demand Resources” is being replaced with the term “the Energy Market.” The term Demand Resource is no longer a defined term, having been replaced with either Demand Response Resource, Active Demand Capacity Resource, or Demand Capacity Resource, depending on context. None of these terms are intended here, however. Instead, this section describes the monitoring of demand bidding practices in the Energy Market. As such, the PRD Revisions replace “Demand Resource” with “the Energy Market” here.

Second, in Section III.A.21.2(b)(ii), the term “Demand Response provider” is being eliminated. Demand Response provider is a now-obsolete defined term that meant “companies that provide technology and services to help customers participate in Demand Response Programs.” There is no precisely equivalent term in use today, but the gist of this section is to capture the costs of acquiring and developing Demand Capacity Resources, so changes are made accordingly. In addition, changes are being made to the rest of the paragraph to use the updated defined terms, Demand Response Resource and Asset.

The changes to Appendix A are summarized in the table below.

Appendix A – Market Monitoring	
Language Reference	Explanation
III.A.(Table of Contents)	Updates to reflect new section titles
III.A.8	Updates term “Shortage Event” to Pay For Performance term, “Capacity Scarcity Condition”
III.A.10	Replaces term “Demand Resources” with term “the Energy Market,” for reasons described in text above
III.A.17.1	Clarifications
III.A.21.1	Updates section reference
III.A.21.1.1	Various ministerial corrections, including updates and corrections to defined terms
III.A.21.1.2	Various ministerial corrections, including updates and corrections to defined terms
III.A.21.2	Updates section references and defined terms, clarifies III.A.21.2(b)(ii), for reasons described in text above
III.A.21.3	Deletes obsolete provision
III.A.23.1	Updates defined terms
III.A.23.4	Updates defined term

G. Market Rule 1, Appendix F – Net Commitment Period Compensation Accounting

As mentioned, under the existing full integration rules, Demand Response Resources are eligible for NCPC credits and charges. The PRD Revisions integrate Demand Response Resources into Appendix F, where the existing NCPC calculations are detailed. The PRD Revisions also revise slightly the ISO’s Order No. 719 compliance changes related to certain deviation charges to buyers under emergency conditions. These changes are discussed below.

1. Making Demand Response Resources Eligible for NCPC Payments on a Basis Comparable to Generator Assets and DARD Pumps

Existing Section III.E2.9.4 makes Demand Response Resources eligible for NCPC credits and charges, but Appendix F, which governs NCPC accounting, does not currently include Demand Response Resources in such accounting. Therefore, the PRD Revisions integrate Demand Response Resources into Section III.F. While the Tariff changes integrating Demand Response Resources into this section are numerous, all of them involve including Demand Response Resource offer parameters and concepts wherever Generator Asset offer parameters and concepts appear, in parallel to those concepts.

The Net Commitment Period Compensation changes are summarized in the table below.

Net Commitment Period Compensation	
Language Reference	Explanation
I.2.2	Adds Demand Reduction Offer to the definition of Economic Dispatch Point
III.F.(Table of Contents)	Updates to conform to the revisions
III.F.1	Incorporates Demand Reduction Offer parameters into terms used in NCPC calculations; clarifies when a Resource is considered to be following Dispatch Instructions for NCPC purposes; clean up changes
III.F.1(h)	Adds a section describing how to gross up Demand Response Resource costs and revenues by average avoided peak distribution losses
III.F.2.1 through III.F.2.1.7	Makes Demand Response Resources (including Fast Start Demand Response Resources) eligible for Day-Ahead NCPC Credits; clean up changes
III.F.2.1.6	Adjusts Day-Ahead NCPC Credit as described in III.F.1(h) (that is, increases by distribution losses); clean up changes
III.F.2.1.7	Adjusts Day-Ahead NCPC Credit for Fast Start Demand Response Resources as described in III.F.1(h) (that is, increases by distribution losses); clean up changes
III.F.2.2.1	Adds Demand Response Resources to the Resources eligible for Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, and Dispatch Lost Opportunity Cost Credits;

Net Commitment Period Compensation	
Language Reference	Explanation
	clean up changes
III.F.2.2.2.1 through III.F.2.2.2.8	Makes Demand Response Resources eligible for Real-Time Commitment NCPC Credits; clean up changes
III.F.2.2.2.3(b)	Sets Demand Response Resource costs to \$0 when there is a negative demand reduction
III.F.2.2.2.4.2	Sets Demand Response Resource revenues to \$0 when LMP is positive and there is a negative demand reduction
III.F.2.2.2.5	Adjusts Real-Time Commitment NCPC Credit as described in III.F.1(h) (that is, increases by distribution losses); clean up changes
III.F.2.2.3 through III.F.2.2.3.5	Makes Demand Response Resources eligible for Real-Time Dispatch NCPC Credits; clean up changes
III.F.2.2.3.5	Adjusts Real-Time Dispatch NCPC Credit as described in III.F.1(h) (that is, increases by distribution losses); clean up changes
III.F.2.2.5 through III.F.2.2.5.3	Makes Demand Response Resources eligible for Real-Time Dispatch Lost Opportunity NCPC Credits
III.F.2.2.5.3	Clean up changes
III.2.3.5.1	Adjusts Maximum Net Revenue as described in III.F.1(h) (that is, increases by distribution losses); clean up changes
III.2.3.5.2	Adjusts Actual Net Revenue as described in III.F.1(h) (that is, increases by distribution losses); clean up changes
III.F.2.3.6 through III.F.2.3.6.2	Makes Demand Response Resources eligible for Cancelled Start NCPC Credits; clean up changes
III.F.2.3.7 through III.F.2.3.7.6	Makes Demand Response Resources (including Fast Start Demand Response Resources) eligible for Hourly Shortfall NCPC Credits; clean up changes
III.F.2.3.7.4	Adjusts Hourly Shortfall NCPC Credit as described in III.F.1(h) (that is, increases by distribution losses); adds Demand Response Resource language parallel to Generator Asset language; clean up changes
III.F.2.3.7.5	Adjusts Hourly Shortfall NCPC Credit for Fast Start Demand Response Resources as described in III.F.1(h) (that is, increases by distribution losses)
III.F.2.3.8.1	Clean up change
III.F.2.3.9 through III.F.2.3.9.8	Makes Demand Response Resources eligible for Real-Time Posturing NCPC Credits; clean up changes

Net Commitment Period Compensation	
Language Reference	Explanation
III.F.2.3.9.8	Adjusts real-time posturing NCPC Credit as described in III.F.1(h) (that is, increases by distribution losses)
III.F.2.3.10 through III.F.3.10.4	Makes Demand Response Resources eligible for Rapid Response Pricing Opportunity Cost NCPC Credits; clean up changes
III.F.2.4	Includes NCPC credits to Demand Response Resources and Fast Start Demand Response Resources to other credits for purposes of assignment and apportionment
III.F.2.5	Clean up change
III.F.3.1.2(d), (g), (i)	Revisions to subsection (d) remove “following Dispatch Instructions while” because fact is immaterial to the Real-Time NCPC Posturing Credit calculation; includes in subsection (g) positive Real-Time Demand Reduction Obligations in the allocation of Total Minimum Generation Emergency Credits; allocates in subsection (i) a proportion of all remaining Real-Time Energy Market NCPC costs to demand reduction deviations for Pool-Scheduled Demand Response Resources not following Dispatch Instructions
III.F.3.1.3(a), (b), (c),(d)	Clarifies that subsection (a) applies to Generator Assets; adds subsection (b) to apply the deviation charges to Demand Response Resources during a Minimum Generation Emergency in a manner comparable to Generator Assets; (c) clean up changes; includes in (d) Order No. 719 compliance language, discussed in Section IV.G.2 below.
III.F.3.2	Clean up changes; adds subsection (e) to describe the allocation of Real-Time Energy Market NCPC Credits to Demand Response Resources not following Dispatch Instructions
III.F.3.3	Clean up changes

2. Order No. 719 Compliance

In Order No. 719, the Commission required ISOs to eliminate, during system emergencies, deviation charges to buyers that take less electric energy in the Real-Time market than they were scheduled to take Day-Ahead.⁶⁰ In 2009, the ISO submitted a filing to comply with this aspect of Order No. 719,⁶¹ but implementation was deferred until Demand Response

⁶⁰ See *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 (2008) at P 111.

⁶¹ See *New England Inc. and New England Power Pool*, Docket No. ER09-1051-000 Filing of ISO New England Inc. and New England Power Pool in Response to Order No. 719 (April 28, 2009) at page 32.

Resources were fully integrated into the wholesale markets. The ISO's Order No. 719 compliance approach will therefore be implemented on June 1, 2018, along with the full integration of demand response. However, since several major market design changes have been made since 2009, the ISO has reviewed its approach to this aspect of Order No. 719. The two revisions that were made as a result of that review are discussed below and in the Yoshimura Testimony.⁶²

Under the ISO's initial approach, accepted by the Commission in 2010, the ISO defined system emergencies, for purpose of this Tariff provision, as intervals in which the ISO had dispatched demand resources or declared Operating Procedure No. 4 (Action During a Capacity Deficiency) or Operating Procedure No. 7 (Action in an Emergency). During such emergency conditions, the ISO would not allocate deviation charges to load that had taken less energy in Real-Time than had been scheduled Day-Ahead. Instead, these deviation charges would be billed to Real-Time Load Obligation in the Load Zone in which the pertinent NCPC charges accrued.

As Mr. Yoshimura explains in his testimony, the PRD Revisions update the conditions that are considered a system emergency for purposes of this Tariff provision. Operating Procedures No. 4 and No. 7 are retained under the revisions as system emergencies. However, the revisions eliminate the dispatch of demand resources as a triggering system emergency, because as of June 1, 2018, the dispatch of demand resources will no longer be an ISO response to system emergencies. In addition, the PRD Revisions add a triggering system emergency: Capacity Scarcity Conditions (during which reserves are scarce), a concept effective June 1, 2018 with the implementation of the Pay for Performance capacity market design.⁶³

The PRD Revisions also modify the allocation methodology for the pertinent deviation charges (that is, those not allocated to load that reduced usage as described in this Tariff provision). Under the approach filed in April 2009, the NCPC costs not charged are billed only to the buyers located in the same Load Zone as the buyer that reduced its energy use – buyers in another Load Zone affected by the same emergency condition who also benefited (from improvements to system reliability and potentially lower LMPs) receive no bill for (reallocation of) NCPC costs. To address this discrepancy, under the PRD Revisions, the NCPC costs not charged are instead billed to Real-Time Load Obligation across all areas of the system affected by the emergency condition.⁶⁴

The following table summarizes the Tariff revisions associated with Order No. 719 compliance.

⁶² Yoshimura Testimony at 25-27.

⁶³ Yoshimura Testimony at 26-27.

⁶⁴ Yoshimura Testimony at 27.

Rules Complying with FERC Order No. 719	
Language Reference	Explanation
III.F.3.1.3(d)	Modifies the deviation charge allocation associated with buyers in the Energy Market during intervals when the ISO takes actions to address certain emergency conditions; this change complies with Order No. 719

H. Miscellaneous and Clean-Up Changes

Finally, the PRD Revisions make a number of other changes, including: the relocation and streamlining of registration rules; the relocation of the Demand Response Baseline provisions along with the elimination of the baseline “reset” provision and a change to data submission on “curtailment days”; the replacement of the annual meter certification process with an ongoing process; revisions to allow slow-starting Demand Response Resources to address projected emergency conditions; and numerous ministerial changes. These revisions are discussed below.

1. Demand Response Asset and Demand Response Resource Registration

To participate in the wholesale markets with a Demand Response Resource, a Market Participant must register one or more Demand Response Assets with the ISO and associate one or more of those assets with a specific Demand Response Resource. The current registration rules for Demand Response Assets and Demand Response Resources are found primarily in Section III.E2.1 of the Tariff. The PRD Revisions make no substantive changes to these requirements, simply relocating them in streamlined form from existing Section III.E2.1 to revised Section III.8.1. Revised Section III.8.1 also includes several subsections related to the registration of Demand Response Assets and Demand Response Resources that are currently found elsewhere in the Tariff; under the PRD Revisions, these provisions are consolidated into this single location.

The following table summarizes the Tariff changes related to asset and resource registration rules.

Asset and Resource Registration	
Language Reference	Explanation
III.8.1.1	Integrates requirements for Demand Response Asset registration from III.E2.1; cleans up language for conformity with this Tariff section; in III.8.1.1.(d) clarifies rule regarding a Demand Response Asset and Generator Asset at the same facility, replacing language deleted from III.13.1; adds to III.8.1.1(h) language removed from existing III.13.1.4.10
III.8.1.2	Integrates requirements for Demand Response Resource

Asset and Resource Registration	
Language Reference	Explanation
	registration from III.E2.1; clarifies what happens when a Demand Response Resource falls below 1MW in the Seasonal DR Audit; changes the term Demand Response Capacity Resource to Active Demand Capacity Resource
Deleted: III.E2.1	Moves registration requirements to revised Section III.8.1.

2. Demand Response Baselines – Reset and Curtailment Days

The rules governing Demand Response Baselines for the period starting June 1, 2018 are currently found in III.8B. As part of the PRD Revisions, Section III.8B is being deleted, and the rules for Demand Response Baselines will now appear in revised Section III.8, following the rules governing Demand Response Asset and Demand Response Resource registration. The relocated baseline rules are largely unchanged, with two small exceptions.

First, under the current rules, following a significant change in load, generation, or reported meter data, the Demand Response Baseline of an existing Demand Response Asset must be reestablished as though the Asset were establishing a baseline for the first time. This is referred to in Section III.8B.2 of the current Tariff as “resetting” a baseline. This baseline “reset” was required because under the prior baseline methodology, the impact of bad data on the baseline continued long after the bad data was submitted. However, as explained in the Yoshimura Testimony, under the new 10-day rolling average baseline methodology accepted by the Commission in 2015,⁶⁵ the impact of any old or bad data on the calculated baseline quickly abates, allowing the ISO to eliminate the complicated and somewhat subjective baseline reset provision.⁶⁶

Second, as explained in the Yoshimura Testimony, under the software that will implement full integration, the baseline calculation will be updated automatically to address any undue baseline distortion from “curtailment days.” (A curtailment is a reduction in demand resulting from scheduled shutdown or maintenance, or from circumstances outside the control of the Demand Response Asset or the Market Participant). On a curtailment day, the metered demand of an affected Demand Response Asset will be substantially lower than normal, and would result in a distorted Demand Response Baseline if used in its computation.⁶⁷

⁶⁵ See *ISO New England Inc. and New England Power Pool*, Docket No. ER16-167-000 and ER16-167-001 (December 23, 2015) (delegated letter order accepting the ISO’s Market Rule 1 Demand Response Changes).

⁶⁶ Yoshimura Testimony at 25.

⁶⁷ Yoshimura Testimony at 23.

To ameliorate the potential for baseline distortion, existing Section III.8B.6.2 requires that Market Participants submit, for the duration of a curtailment, meter data that is equal to the last unadjusted baseline of each affected Demand Response Asset. However, as noted above and in the Yoshimura testimony, the software that will implement full integration automatically addresses any undue baseline distortion from curtailments. Therefore, under full integration, Market Participants will no longer need to submit anything other than actual meter data for all days, which greatly simplifies baseline administration for both Market Participants and the ISO.⁶⁸

The revisions related to Demand Response Baselines are summarized below.

Demand Response Baselines – Reset Elimination and Curtailment Days	
Language Reference	Explanation
Deleted: III.E2.8	Eliminates reference to baseline information
III.8.2	Reorganizes existing language from III.8B
III.8.2.1	Clarifies how weekday non-holiday Demand Response Baselines are calculated
III.8.2.2	Clarifies how Saturday Demand Response Baselines are calculated
III.8.2.3	Clarifies how Sunday and holiday Demand Response Baselines are calculated
III.8.2.4	Clarifies how the Demand Response Baselines are adjusted
III.8.3	Clarifies how forced and scheduled curtailments are treated in the baseline calculations
III.8.4	Describes Demand Response Asset Energy Market performance calculation
Deleted: III.8B.2	Deletes language describing baseline reset
Deleted: III.8B.6	Deletes section on establishing Demand Response Baselines on curtailment days, including, in Section III.8B.6.2, meter data submission rules for curtailment days
Deleted: Remainder of III.8B	Deletes because reorganized into new sections of III.8

3. Meter Data Certification

The current rules require that Market Participants with Demand Response Resources perform an annual independent certification of the accuracy and precision of the meters, telemetry measurement devices, and data communication systems used to provide data to the ISO. As Mr. Yoshimura observes in his testimony, however, with the ability of Demand Response Resources to provide Operating Reserve, the necessity for accurate meter and

⁶⁸ Yoshimura Testimony at 23.

telemetry data is heightened.⁶⁹ The ISO therefore plans to replace the annual certification process with an ongoing process that requires Market Participants with Demand Response Resources to immediately notify the ISO of any meter or telemetry accuracy problems. As is true today, issues with metering, telemetry or data communication systems can also be revealed during periodic analyses conducted by the ISO. Under the PRD Revisions, once an issue is identified, the Market Participant must either indicate to the ISO when the issue will be resolved or it must retire the affected Demand Response Asset(s). Once such problems become known, and until they are resolved, the demand reduction capability of the affected Demand Response Asset(s) will be excluded from the Demand Response Resource with which it is associated.⁷⁰

The modified requirements related to meter data certification are shown in the table below.

Meter Data Certification	
Language Reference	Explanation
Deleted: III.E2.1	Moves applicable Demand Response Registration information into III.8.1
Deleted: III.E2.2	Moved requirement to III.3.2.2
III.3.2.2(a)	Clarifies that metering and telemetry requirements in this section does not apply to Demand Response Assets
III.3.2.2(b)	Clarifies that meter maintenance and testing rules apply to all Assets
III.3.2.2(c)	Specifies metering and telemetry requirements for Demand Response Assets, moved from III.E2; clarifies language moved from III.E2; describes how to resolve accuracy problems and consequences if issues with metering and telemetry devices are not resolved; clarifies that the market participant shall “promptly notify the ISO” of any metering or telemetry problems; removes detail addressed in manuals and operating procedures for consistency with other resources

4. Slow-Start Demand Response Resources in Emergency Conditions

The existing Tariff allows the ISO to commit very slow-starting generators (that is, Generator Assets with Notification Times exceeding 24 hours) to alleviate or mitigate a projected emergency condition. In a comparable manner, the PRD Revisions modify the Tariff to allow the ISO to commit any very slow-starting Demand Response Resources to address a projected emergency condition. Revisions to a single section are required to implement this change.

⁶⁹ Yoshimura Testimony at 21.

⁷⁰ Yoshimura Testimony at 22.

Using Slow-Start Demand Response Resources in Emergency Conditions	
Language Reference	Explanation
III.1.10.1(e)	Gives slow-start Demand Response Resources equivalent treatment to slow-start Generators

5. Other Changes

The PRD Revisions also include numerous non-substantive Tariff changes, which clarify or correct the Tariff to, among other things, reflect the intent of the market design, remove redundant or obsolete provisions, correct inconsistent terminology and typographical errors, update the language with newly defined terms, properly order existing sections, and correct internal Tariff section references.⁷¹ A table summarizing these changes is below.

Tariff Clarifications, Corrections and Clean Up	
Language Reference	Explanation
Table of Contents	Changes to conform to Tariff revisions
I.2.2	Adds purchase of demand reductions to the definition of Day-Ahead Energy Market, removes obsolete reference to III.E2
I.2.2	Clean up change to definition of Demand Response Resource Notification Time and Demand Response Resource Start-Up Time
I.2.2	Removes Demand Response Regulation Resource from definition of Dispatchable Resource
I.2.2	Deletes duplicate definition of Fast Start Generator
I.2.2	Updates section references within the following definitions: Real-Time Energy Market, Real-Time Energy Market Deviation Congestion Charge/Credit, Real-Time Energy Market Deviation Energy Charge/Credit, Real-Time Energy Market Deviation Loss Charge/Credit, Real-Time Generation Obligation, Real-Time Generation Obligation Deviation, Real-Time Load Obligation, Real-Time Load Obligation Deviation, Real-Time Locational Adjusted Net Interchange, Real-Time Locational Adjusted Net Interchange Deviation, Real-Time Loss Revenue, Real-Time Congestion Revenue, Demand Response Baseline, Demand Response Asset, Demand Resource, Day-Ahead Energy Market Congestion Charge/Credit, Day-Ahead Energy Market Energy Charge/Credit, Day-Ahead Energy Market Loss Charge/Credit, Day-Ahead Loss Charges or Credits, Day-Ahead

⁷¹ Yoshimura Testimony at 27-28.

Tariff Clarifications, Corrections and Clean Up	
Language Reference	Explanation
	Loss Revenue, Demand Reduction Threshold Price, Day-Ahead Load Obligation, Day-Ahead Generation Obligation, Day-Ahead Locational Adjusted Net Interchange, Day-Ahead Loss Charges or Credits, Day-Ahead Loss Revenue, Inadvertent Energy Revenue, Inadvertent Energy Revenue Charges or Credit, Marginal Loss Revenue Load Obligation, Winter Capability Period, Existing Demand Capacity Resource, Capacity Scarcity Condition, Summer Capability Period, Dispatch Zone, New Demand Capacity Resource, New Demand Capacity Resource Qualification Package, New Demand Capacity Resource Show of Interest Form
III.3.2.7	Removes obsolete reference to III.E2
III.3.6.3	Adds reference to ISO Manuals for Data Revision deadlines
III.9.5.2	Clarifying change
III.3.2.2(d), III.13.1.1.2.9, III.13.1.2.3.1, III.13.1.4.1.1.1, III.13.1.4.1.1.2, III.13.1.4.1.1.2.1, III.13.1.4.1.1.2.2, III.13.1.4.1.1.2.3, III.13.1.4.1.1.2.4, III.13.1.4.1.1.2.5, III.13.1.4.1.1.2.6, III.13.1.4.1.1.2.7, III.13.1.4.1.1.2.8, III.13.1.4.1.1.3, III.13.1.4.1.1.4, III.13.1.4.1.1.5, III.13.1.4.1.1.6, III.13.1.4.3.2, III.13.1.5, III.13.1.5A, III.13.1.6, III.13.1.7, III.13.1.9, III.13.1.11, III.13.2.3.2(d), III.13.2.5.2.1(e), III.13.2.7.3, III.13.3.2.2(b)(ii), III.13.3.7, III.13.6.1.5.4.1, III.13.6.1.5.2, III.13.6.2.5.2,	Section reference clean up

Tariff Clarifications, Corrections and Clean Up	
Language Reference	Explanation
III.13.7.3.1, III.13.8.1	
III.13.1.3	Capitalization clean up
Deleted: III.13.1.4.6.1	Relocates rules for establishing Dispatch Zones to appropriate location in III.12.4A
III.13.1.4.4, III.13.1.4.5, III.13.1.4.8, III.13.1.4.9	Deletes “[Reserved.]” sections
Deleted: III.13.1.4.10	Relocates requirement to III.8.1.1(h)
Deleted: III.13.1.4.11	Relocates requirement to III.13.6.1.5.3(a)
III.13.6.1.1- III.13.6.1.5	Changes headings to clarify that the rules in this section apply to Resources with Capacity Supply Obligations
III.13.6.1.5.1	Clarifies “Demand Reduction Offer”; removes (ii) because it is not needed – if a resource cannot meet the 72 hour standard in (i), meeting the standard in (ii) will not make it dispatchable; relocates the provision that passive Demand Capacity Resources may not participate in the energy market
III.13.6.1.5.2	Cleans up section title
III.13.6.1.5.3	Relocates to (a) language on mapping restrictions (in revised form) from existing III.13.1.4.11; clarifies in (d) and (e) measurement, verification, data collection and outage requirements of Demand Capacity Resources (in addition to auditing requirements, which are discussed in Section IV.E.6 above)
III.13.6.2.1, III.13.6.2.3, III.13.6.2.5	Changes headings to clarify that the rules in this section apply to Resources without Capacity Supply Obligations
III.13.6.2.5.1	Removes redundant final clause (covered in III.1.10.1A); clean up changes
III.13.6.2.5.1.1, III.13.6.2.5.1.2	Removes unnecessary references to Demand Response Resources not associated with Demand Response Capacity Resources
III.13.6.2.5.2	Clarifies that the section is applicable to all Demand Capacity Resources; specifies that (b) and (c) apply to Active Demand Capacity Resources
III.13.7.2.2(f)	Adds reference to adjustment described in III.9.6.5(h)
III.13.7.2.4	Clarifies terminology
III.13.7.5.1	Clarifying change
Deleted: III.E2	Deletes Appendix as the provisions of III.E2 were moved into the main body of Market Rule 1

V. STAKEHOLDER PROCESS

The PRD Revisions filed herein were considered through the complete NEPOOL Participant Processes and received the unanimous support of NEPOOL. Through the NEPOOL Participant Processes, portions of the PRD Revisions were considered and voted on separately by the NEPOOL Markets Committee, the NEPOOL Reliability Committee, and the NEPOOL Transmission Committee.

The NEPOOL Markets Committee reviewed and considered a majority of the PRD Revisions over the course of several meetings, and at its June 13-14, 2017 meeting, unanimously approved a resolution to recommend Participants Committee support for changes to Market Rule 1 and Section I.2.2 of the Tariff.⁷²

On June 20, 2017, the NEPOOL Reliability Committee voted unanimously to recommend Participants Committee support for the revisions related to Demand Response Resource auditing in Tariff Sections III.1.5 and III.9.5.3 as well as for revisions to Sections III.12 and I.2.2.⁷³

At its June 22, 2017 meeting, the NEPOOL Transmission Committee considered and unanimously approved a motion to recommend that the Participants Committee support revisions to the Tariff definitions section (Section I.2.2.) and a clean-up terminology change to Section I.3.9.3 of the Tariff.⁷⁴

Subsequent to NEPOOL Technical Committee and Subcommittee review, the NEPOOL Participants Committee, at its June 27, 2017 meeting, considered and voted unanimously to support the complete package of PRD Revisions (with one abstention noted).

VI. 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.⁷⁵ Notwithstanding the request for

⁷² During the June 14 Markets Committee vote, there was one abstention registered by a member in NEPOOL's Supplier Sector.

⁷³ At the June 20 Reliability Committee meeting, two abstentions were noted; one within the Generation Sector and one within the Supplier Sector.

⁷⁴ During the June 22 Transmission Committee vote, one abstention was registered by a member in the Supplier Sector.

⁷⁵ 18 C.F.R. § 35.13 (2016).

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;
- Testimony of Henry Y. Yoshimura, sponsored solely by the ISO.
- Redlined Tariff sections effective June 1, 2018;
- Clean Tariff sections effective June 1, 2018; and
- 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 I above, the Filing Parties request that the PRD Revisions become effective on June 1, 2018.

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 <https://www.iso-ne.com/participate/participant-asset-listings/directory?id=1&type=committee>. 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 VI of this transmittal letter.

35.13(b)(5) – The reasons for this filing are discussed in Section IV 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.

VII. CONCLUSION

For the reasons set forth above, the Filing Parties request that the Commission accept this filing with the PRD Revisions to become effective on June 1, 2018.

Respectfully submitted,

ISO NEW ENGLAND INC.

**NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE**

By: /s/_____

By: /s/_____

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**UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

ISO New England Inc.

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Docket No. ER17-____-000

**PREPARED TESTIMONY OF HENRY Y. YOSHIMURA
ON BEHALF OF ISO NEW ENGLAND INC.**

1 **I. WITNESS IDENTIFICATION**

2 **Q: Please state your name, position, and business address.**

3 A: My name is Henry Y. Yoshimura. I am the Director of Demand Resource
4 Strategy at the ISO. My business address is One Sullivan Road, Holyoke,
5 Massachusetts 01040-2841.

6

7 **Q: Please describe your work experience, responsibilities, and educational
8 background.**

9 A: I began my career in 1983 at the Massachusetts Department of Public Utilities
10 where, among other things, I directed the regulatory effort that helped
11 Massachusetts be among the first states to incorporate energy efficiency into the
12 utility planning, resource acquisition, and ratemaking processes. Starting in 1992,
13 I became a consultant and advised several state governments in the United States
14 and abroad on developing and implementing electric industry restructuring laws,
15 regulations, and plans.

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I joined the ISO in 2002. Currently, I direct the ISO’s Demand Resource Strategy Department to develop market designs that integrate demand resources – which include demand response, distributed generation, and energy efficiency – into wholesale capacity, energy, and ancillary service markets. To that end, I work with the ISO’s Market Development, System Operations, System Planning, IT and Legal Departments, as well as external stakeholders (including Market Participants, New England Power Pool (“NEPOOL”) Participants, and state and federal regulators). Among my achievements while at the ISO, I worked with stakeholders to develop the market design and rules that made New England the first region to allow demand resources to directly participate in the wholesale capacity market.

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”). I currently serve on the Advisory Council for the Smart Electric Power Alliance (“SEPA”), which acquired ADS in 2015. SEPA is an educational, non-profit industry association with over 1,000 members that helps the electric utility industry deploy and integrate solar, storage, demand response, and other distributed energy resources.

1 I also serve as the Chair of the Demand Resources Working Group, which is a
2 standing working group of the NEPOOL Markets Committee that reviews
3 proposed changes to the Tariff and manuals pertaining to demand resources, as
4 assigned by the Markets Committee.

5

6 I have bachelor and graduate degrees in economics from the University of
7 Montana. I have over 30 years of domestic and international experience as an
8 economist and public policy expert in the electric power industry.

9

10 **II. OVERVIEW AND ORGANIZATION**

11 **Q: What is the purpose of your testimony?**

12 A: The purpose of my testimony is to explain a number of Tariff revisions the ISO is
13 filing to fully integrate demand response into New England's wholesale electricity
14 markets on June 1, 2018. This set of revisions is the last in a series of changes that
15 began with the ISO's Order No. 745 compliance filing.

16

17 The overarching full integration market design and majority of associated Tariff
18 revisions have been submitted over the course of a number of years and accepted
19 by the Commission in multiple orders. The package of changes filed here
20 addresses a number of outstanding issues. In some cases, the revisions incorporate
21 demand response into market mechanisms that deliberately had not included
22 demand response due to uncertainty surrounding the Commission's jurisdiction
23 (for example, the Energy Market offer flexibility revisions developed and filed in

1 2013 and 2014 deliberately omitted demand response). In other cases, the
2 revisions address details not specifically addressed in prior demand response
3 integration filings (for example, the auditing process for Demand Response
4 Resources). Still other changes result from the reorganization of existing Tariff
5 language (for example, these revisions incorporate Appendix E, Demand
6 Response, into the main body of Market Rule 1). Finally, the revisions include
7 many smaller clarifying and remedial changes.

8

9 **Q: Please say a little more about what you mean by the full integration of**
10 **demand response into the wholesale markets.**

11 A: The purpose of demand response full integration is to integrate demand response
12 into the existing market structures in a manner comparable to other resources. Full
13 integration encompasses three broad categories of changes, which allow Demand
14 Response Resources to: (1) participate directly in the Day-Ahead and Real-Time
15 Energy Markets along with other energy resources; (2) provide Operating Reserve
16 and participate directly in the Forward Reserve Market; and (3) receive
17 obligations and compensation in the Forward Capacity Market that are fully
18 comparable with those of other dispatchable resources. I will say a little more
19 about each here:

20

21 *Day-Ahead and Real-Time Energy Markets* – Integration is accomplished by
22 enabling Demand Response Resources to submit Demand Reduction Offers into
23 the Day-Ahead and Real-Time Energy Markets, which will be used to optimally

1 commit and dispatch Demand Response Resources in conjunction with all other
2 energy resources, such as Generator Assets and Dispatchable Asset Related
3 Demands (“DARDs”). Demand Response Resources can be thought of as
4 supplying energy to the market through demand reduction.

5
6 *Operating Reserve and the Forward Reserve Market* – Once Demand Response
7 Resources are integrated into the Energy Markets, Demand Reduction Offers in
8 conjunction with all other Energy Market supply offers will be used to co-
9 optimally dispatch and designate resources to provide energy and Operating
10 Reserve so as to produce the most economically efficient outcome to meet both
11 energy and reserve requirements. Expanding the potential for additional resources
12 to supply comparable energy and Operating Reserve services in Real-Time and on
13 a forward basis through the Forward Reserve Market can provide for a more
14 reliable electric system and increase competition among the suppliers of those
15 services.

16
17 *Demand response obligations and compensation in the Forward Capacity Market*
18 – With the integration of Demand Response Resources into the energy and
19 reserve markets, all dispatchable resources participating in the capacity market,
20 including Demand Response Resources, can receive fully comparable Forward
21 Capacity Market obligations and compensation, reducing potential market
22 distortions.

23

1 **Q: Please explain the nomenclature used in the Tariff revisions to describe the**
2 **entities that provide demand response to the wholesale market.**

3 A: Demand Response Resources, first introduced in the ISO's Order No. 745
4 compliance filing, will participate in the Day-Ahead and Real-Time Energy
5 Markets beginning on June 1, 2018. They will submit Demand Reduction Offers
6 and receive Dispatch Instructions from the ISO, and will provide energy and
7 reserves. Demand Response Resources are themselves composed of one or more
8 Demand Response Assets, each of which is typically a single end-use customer
9 facility; when a Demand Response Resource is dispatched, it responds by
10 deploying one or more of its Demand Response Assets. Under the revisions as
11 under the existing Tariff, the performance of a Demand Response Asset is
12 calculated by subtracting its metered consumption in an interval from its adjusted
13 Demand Response Baseline in the same interval. The Demand Response Baseline
14 (under the revisions and under the exiting Tariff) is calculated based on the
15 Asset's average consumption over a number of previous days, and the *adjusted*
16 Demand Response Baseline takes into account the Demand Response Asset's
17 consumption immediately prior to dispatch.

18
19 Under the revisions, one or more Demand Response Resources can be
20 incorporated into an entity that participates in the Forward Capacity Market,
21 where it is referred to as an Active Demand Capacity Resource. (This term is
22 introduced for the first time with these revisions, where for clarity's sake it
23 replaces the term Demand Response Capacity Resource, a term some found

1 confusing.) Active Demand Capacity Resources will participate in the capacity
2 market beginning on June 1, 2018.

3

4 Under today's Tariff, the umbrella term "Demand Resources" refers to one of
5 four types of resources that participate in the Forward Capacity Market by
6 reducing demand. Two of these types, On-Peak Demand Resources and Seasonal
7 Peak Demand Resources (so-called "passive" Demand Resources) are carried
8 over into full integration largely unchanged. The other two types – Real-Time
9 Demand Response Resources and Real-Time Emergency Generation Resources –
10 were eliminated in a filing earlier this year and will be removed from the Tariff
11 effective June 1, 2018. As mentioned above, a third type of demand resource was
12 added in prior full integration filings, which under the instant revisions is referred
13 to as an Active Demand Capacity Resource. In these revisions, the umbrella
14 capacity market term "Demand Resource" is changed to "Demand Capacity
15 Resource." (This change makes the term parallel to the capacity market terms
16 Generating Capacity Resource and Import Capacity Resource.)

17

18 In sum, as of June 1, 2018, Demand Response Resources participate in the energy
19 and reserve markets, and are composed of one or more Demand Response Assets.
20 Demand Capacity Resources participate in the Forward Capacity Market, where
21 they can be one of three types: Active Demand Capacity Resources (which are
22 composed of one or more Demand Response Resources, which in turn consist of
23 one or more Demand Response Assets), On-Peak Demand Resources, or Seasonal

1 Peak Demand Resources (like today, On-Peak and Seasonal Peak Demand
2 Resources consist of Assets and measures).

3

4 **Q: How is your testimony organized?**

5 A: My testimony does not attempt to explain all the changes included in the full
6 integration revisions. Many of the changes are straight-forward, ministerial
7 revisions the explanations for which are readily apparent; these revisions are
8 discussed solely in the filing letter. My testimony instead addresses those changes
9 whose purpose or supporting rationale my expertise can help elucidate for the
10 Commission and its staff.

11

12 My testimony is organized around the more substantial issues raised by the
13 revisions, and consists of four sections in addition to these introductory
14 paragraphs. Section III discusses Energy and Operating Reserves; Section IV
15 discusses Auditing; Section V is Metering, Measurement, and Verification; and
16 Section VI, entitled Other, discusses several remaining miscellaneous revisions.
17 The issues addressed in each section are as follows:

1 Section III: Energy and Operating Reserves

- 2 • Extending Energy Market offer flexibility provisions to Demand Response
- 3 Resources
- 4 • Prohibiting intraday changes to certain offer parameters
- 5 • Demand Response Resource aggregation zones and their use in Locational
- 6 Marginal Price (“LMP”) formation and Demand Response Resource
- 7 dispatch
- 8 • Demand Response Resource “offer floor” to be used in clearing,
- 9 dispatching, and pricing
- 10 • Revising the definition of Ten-Minute Spinning Reserve

11 Section IV: Auditing

- 12 • Energy audits (Claimed Capability Audits)
- 13 • Reserve audits (CLAIM10 and CLAIM30 audits)

14 Section V: Metering, Measurement, and Verification

- 15 • Replacing the meter data certification process
- 16 • The submission of Measurement and Verification Plans only by passive
- 17 Demand Capacity Resources
- 18 • Data submissions during curtailments

19 Section VI: Other

- 20 • Real-Time Energy Market settlement
- 21 • Elimination of the baseline reset provision
- 22 • Order No. 719 compliance

23

1 **III. ENERGY AND OPERATING RESERVES**

2 **Q: Do the revisions extend energy market offer flexibility to Demand Response**
3 **Resources?**

4 A: Yes. In 2014, the ISO implemented energy market enhancements to provide
5 greater flexibility to Market Participants to structure and modify their supply
6 offers in the Day-Ahead and Real-Time Energy Markets. Among other things,
7 these changes allowed generators and DARDs to (1) submit distinct hourly offers
8 into the Day-Ahead and Real-Time Energy Markets and (2) update their cost-
9 related offer parameters within the Operating Day, until 30 minutes prior to the
10 hour in which the offer applies. The instant revisions allow Demand Response
11 Resources to do so as well, except where such flexibility conflicts with the self-
12 scheduling prohibition that was previously accepted by the Commission.

13
14 Specifically, the revisions allow Demand Response Resources to submit hourly
15 price/demand reduction quantity pairs, and update the parameters included in
16 these offers during the Re-Offer Period for the Operating Day. And, under the
17 revisions as under the existing Tariff, Demand Response Resources (like
18 Generator Assets and DARDs) are expected to keep their physical offer
19 parameters up-to-date throughout the Operating Day.

20
21 As noted above, under the existing Tariff, self-scheduling by Demand Response
22 Resources is not permitted, and these revisions do not change that. Upon review,
23 however, the ISO has determined that there are several financial and intertemporal
24 offer parameters that, if changed by Demand Response Resources during the

1 Operating Day, would permit such resources to effectively self-schedule. As such,
2 the revisions do not allow Demand Response Resources to change the following
3 offer parameters after the initial Reserve Adequacy Analysis: price/demand
4 reduction pairs, Interruption Cost, Demand Response Resource Notification Time,
5 Demand Response Resource Start-Up Time, Minimum Reduction Time, and
6 Minimum Time Between Reductions.

7

8 **Q: Please explain how allowing a Demand Response Resource to change certain**
9 **financial or intertemporal offer parameters during the Operating Day would**
10 **effectively allow it to self-schedule.**

11 A: Allowing Demand Response Resources to change their financial parameters (offer
12 price or Interruption Cost) and allowing them to change their intertemporal
13 parameters results in effective self-scheduling through slightly different
14 mechanisms.

15

16 First, financial parameters: Demand Response Resources should only be paid for
17 reducing demand if the reduction would not have occurred in the normal course of
18 business. Paying a Demand Response Resource to reduce demand if it would have
19 reduced demand anyway, in the absence of payment, only raises costs and
20 produces no incremental benefit. If allowed, a Demand Response Resource could
21 strategically lower its offer prices and/or Interruption Costs during the Operating
22 Day whenever it knew that its consumption in upcoming intervals was to be
23 below average, (that is, below its calculated Demand Response Baseline), so as to

1 receive a Dispatch Instruction to reduce demand (which it would have done
2 anyway) and a corresponding energy payment. This would effectively amount to
3 self-scheduling. Accordingly, the revisions do not allow Demand Response
4 Resources to change offer prices or Interruption Costs after the initial Reserve
5 Adequacy Analysis for the Operating Day.

6
7 Second, intertemporal parameters: Allowing Demand Response Resources to
8 change intertemporal parameters (Minimum Reduction Time, Minimum Time
9 Between Reductions, Demand Response Resource Notification Time, or Demand
10 Response Resource Start-Up Time) during the Operating Day provides a different
11 opportunity for what amounts to self-scheduling. For example, a Demand
12 Response Resource that has been committed or dispatched could increase its
13 period of dispatch simply by increasing its Minimum Reduction Time during its
14 commitment. Alternatively, a Demand Response Resource that the ISO had
15 committed to reduce demand twice during an Operating Day (for example, from
16 10:00-12:00 and again from 14:00-16:00) could effectively self-schedule during
17 the interim 12:00-14:00 period by increasing its Minimum Time Between
18 Reductions (or by changing the sum of its Demand Response Resource
19 Notification Time and Demand Response Resource Start-Up Time) to a period
20 greater than two hours. With a Minimum Time Between Reductions (or a
21 combined notification and start-up time) of over two hours, the only way the ISO
22 can bring the resource back by 14:00 (the beginning of the second commitment)
23 would be to allow it to continue reducing demand between the two periods. The

1 Demand Response Resource would have effectively self-scheduled between 12:00
2 and 14:00.

3

4 **Q: Please describe the Tariff changes related to Demand Response Resource**
5 **LMP formation and dispatch.**

6 A: Where a Demand Response Resource consists of multiple Demand Response
7 Assets, all such Assets must be located within the same Dispatch Zone – or,
8 where a Dispatch Zone contains more than one Reserve Zone, all must be located
9 within the same Dispatch Zone and Reserve Zone. The revisions introduce a new
10 defined term, DRR Aggregation Zone, in place of the more cumbersome and less
11 precise “same Dispatch Zone and Reserve Zone.”

12

13 Under the previously accepted full integration rules, a Demand Response
14 Resource registered at a Dispatch Zone is paid the LMP and Reserve Market
15 Clearing Price for the Dispatch Zone. This means that, even though a Reserve
16 Zone boundary can bisect a Dispatch Zone (that is, as mentioned, a Dispatch Zone
17 can span more than one Reserve Zone – there is one such Dispatch Zone today),
18 only a single LMP and single Reserve Market Clearing Price will be created for
19 the entire Dispatch Zone. This is true even where congestion occurs across the
20 Reserve Zone boundary or where the reserve prices are different in the two
21 Reserve Zones. Because of this, congestion that occurs between Reserve Zones is
22 incorrectly reflected in a single, uniform Dispatch Zone LMP, and a Demand
23 Response Resource could be compensated via local reserve pricing for a Reserve

1 Zone in which it is not physically located. The instant revisions address this issue
2 by creating separate and distinct pricing locations called, as noted above, DRR
3 Aggregation Zones.

4
5 DRR Aggregation Zones provide appropriate energy and reserve pricing
6 locations, so that any congestion that occurs at the Reserve Zone interface can be
7 properly reflected in the DRR Aggregation Zone LMP, and so that Demand
8 Response Resources can receive the Reserve Market Clearing Price for the
9 Reserve Zone in which they are located. This allows for the economic dispatch of
10 Demand Response Resources that are located in Dispatch Zones that span
11 multiple Reserve Zones, and for the dispatch of resources to maintain reserve
12 requirements in each Reserve Zone.

13
14 At the present time, this change only impacts the Western Connecticut Dispatch
15 Zone, which includes portions of both the Southwestern Connecticut and
16 Connecticut Reserve Zones.

17
18 **Q: Is the ISO making any revisions related to the “offer floor” for Demand**
19 **Response Resources?**

20 A: Yes, the ISO is making a small revision. In its first Order No. 745 compliance
21 filing, the ISO established a Demand Reduction Threshold Price (“DRTP”) to
22 determine, as directed by the Commission, when it is cost-effective to pay the
23 LMP to Demand Response Resources. The DRTP is essentially an offer floor – all

1 Demand Reduction Offers must be submitted at prices at or above the DRTP. The
2 DRTP is recalculated monthly.

3

4 Under the existing Energy Market rules, a Demand Reduction Offer submitted for
5 an Operating Day will, like a Supply Offer, roll over into future Operating Days
6 until replaced by a new offer. Therefore, under the existing rules, if the DRTP
7 increases from one month to the next, a Demand Reduction Offer that rolls over
8 into a future month could end up being less than the DRTP. To address this
9 possibility, the revisions require that the greater of the offer price or the DRTP be
10 used in Day-Ahead Energy Market clearing and Real-Time Energy Market
11 commitment, dispatch and pricing. However, the ISO will continue using the
12 submitted offer price in any Net Commitment Period Compensation (“NCPC”)
13 cost calculations because resources should not receive NCPC compensation to a
14 level greater than their costs, which are expressed in the resource’s offer.

15

16 **Q: How and why is the ISO revising the definition of Ten-Minute Spinning**
17 **Reserve?**

18 A: Under the current full integration rules, all Demand Response Resources with
19 one-minute telemetry and without any controllable behind-the-meter generation
20 are eligible to provide Ten-Minute Spinning Reserve, even if they have not been
21 dispatched. This means that, under the current rules, a Demand Response
22 Resource that has not received a Dispatch Instruction and has not completed its
23 Demand Response Resource Notification Time and Demand Response Resource

1 Start-Up Time can provide Ten-Minute Spinning Reserve. In contrast, only a
2 Generator Asset that is online (having received a Dispatch Instruction, completed
3 its Notification Time, closed its breaker, completed its Start-Up Time and
4 operating at least at its Economic Minimum Limit) is eligible to provide Ten-
5 Minute Spinning Reserve.

6
7 The initial rationale for treating Demand Response Resources and Generator
8 Assets differently was that only *online* generators are synchronized with the grid,
9 whereas Demand Response Resources, because they are load, are always
10 synchronized with the grid. However, on further review, the ISO has determined
11 that the inconsistency between the treatment of Demand Response Resources and
12 generators is not justified.

13
14 Ten-Minute Spinning Reserves are the highest quality reserves available in New
15 England because the resources that provide them are already on dispatch,
16 operating at least at their Economic Minimum Limit (or Minimum Consumption
17 Limit, in the case of DARDs). The current rules do not allow offline generators to
18 provide Ten-Minute Spinning Reserve because, among other things, offline
19 generators are not synchronized with the grid and require a Dispatch Instruction
20 and notification and start-up time before they can provide energy to the grid at
21 their Economic Minimum Limit (even if that notification plus start-up time is
22 zero). Similarly, Demand Response Resources that have not been dispatched also
23 require notification and start-up time prior to reducing their energy consumption

1 from the grid at their Minimum Reduction (for this reason, the market design
2 allows Demand Response Resources to specify a Demand Response Resource
3 Notification Time and a Demand Response Resource Start-Up Time in their
4 Demand Reduction Offers). Therefore, a Demand Response Resource that has not
5 been dispatched is analogous to an offline generator and should not be eligible to
6 provide Ten-Minute Spinning Reserve.

7
8 Conversely, a Demand Response Resource that has been dispatched, has
9 completed its notification and start-up times, and is reducing demand at its
10 Minimum Reduction has demonstrated that it has received a Dispatch Instruction
11 and that its Demand Response Assets, comprised of customer facilities that
12 produce the demand reduction, are responding to the instruction. Since both
13 Generator Assets and Demand Response Resources that have been dispatched and
14 are responding to Dispatch Instructions have completed their notification and
15 start-up times and are operating at least at their minimum production or reduction
16 levels, they should be treated comparably in the provision of Ten-Minute
17 Spinning Reserve.

18

19 **IV. AUDITING**

20 **Q: Why must changes be made to the auditing rules as part of demand response**
21 **full integration?**

22 A: Because demand response currently participates primarily in the Forward
23 Capacity Market, the auditing rules for demand response are currently found in

1 the Forward Capacity Market rules, and the entities that are audited pursuant to
2 these rules are demand response *capacity* resources. With the integration of
3 Demand Response Resources into the energy and reserve markets, however,
4 audits must be instituted to establish the capability of Demand Response
5 Resources to provide energy and Operating Reserves. The revisions establish two
6 different types of audits for Demand Response Resources, parallel to those for
7 Generator Assets: Claimed Capability Audits, to determine their ability to provide
8 energy, and CLAIM10 and CLAIM30 audits, to determine their ability to provide
9 reserves from an undispached state.

10

11 **Q: Please describe how Claimed Capability Audits will be performed for**
12 **Demand Response Resources.**

13 A: Just as a Claimed Capability Audit of a Generator Asset establishes the real power
14 output capability of the generator, the Claimed Capability Audit of a Demand
15 Response Resource establishes the resource's demand reduction capability.
16 Claimed Capability Audits provide the ISO with necessary information about the
17 demonstrated capability of each resource providing energy into the Energy
18 Market. Each summer and winter season during the Capability Demonstration
19 Year, each Demand Response Resource will be required to conduct a Seasonal
20 DR Audit, comparable to the Seasonal Claimed Capability Audits conducted by
21 Generator Assets. The Capacity Demonstration Year is the period from
22 September 1 through August 31, with the summer audit season defined as April
23 through November, and the winter audit season defined as December through

1 March. Each Seasonal DR Audit will be one hour in duration, the same audit
2 duration as that provided in the current Forward Capacity Market audit rules for
3 demand response.

4
5 The auditing rules for Demand Response Resources will be analogous to those of
6 Generator Assets. A Demand Response Resource can request that it be dispatched
7 by the ISO in order to be audited, or can request that its performance during a
8 qualifying dispatch serve as its Seasonal DR Audit. Demand Response Resources,
9 like Generator Assets, are subject to ISO-Initiated Capability Audits of
10 operational parameters – an ISO-Initiated Capability Audit also fulfills the
11 Demand Response Resource seasonal audit requirement. Similar to Establish
12 Claimed Capability Audits of Generator Assets, requested Seasonal DR Audits
13 are unannounced, are performed within five business days of the request, and are
14 conducted between 08:00-22:00 on Non-NERC holiday weekdays.

15
16 When an audit is conducted, the Demand Response Resource is dispatched by the
17 ISO, and the performance of each Demand Response Asset that is part of the
18 Demand Response Resource is measured by taking the difference between each
19 Asset's adjusted Demand Response Baseline and its metered demand during the
20 duration of the audit. A Demand Response Resource's Seasonal DR Audit value
21 is the sum of the most recent audit values of its constituent Assets for that season.
22 A Demand Response Resource's Seasonal DR Audit value can change if Demand
23 Response Assets are added to or removed from the Demand Response Resource,

1 or when the Demand Response Resource performs a new Seasonal DR Audit.
2 Demand Response Resources that fail to audit in a season will be assigned a zero
3 audit value.

4

5 **Q: Please describe how CLAIM10 and CLAIM30 audits will be performed for**
6 **Demand Response Resources.**

7 A: The ISO evaluates the ability of resources to provide Operating Reserve from an
8 undispached state by requiring that all resources wishing to do so conduct
9 CLAIM10 and/or CLAIM30 audits; the revisions add Demand Response
10 Resources to this existing Tariff structure. Therefore, under the revisions,
11 CLAIM10 and CLAIM30 audits establish the ability of a Demand Response
12 Resource to reduce demand from an undispached state after 10 and 30 minutes
13 have elapsed following the issuance of a Dispatch Instruction. All Demand
14 Response Resources will be evaluated for non-spinning Thirty-Minute Operating
15 Reserve, while only Demand Response Resources that consist entirely of Demand
16 Response Assets reporting one-minute telemetry (or less) will be evaluated for
17 Ten-Minute Non-Spinning Reserve.

18

19 The demand reduction achieved by a Demand Response Resource at the 10- and
20 30-minute points after dispatch are used to establish the Demand Response
21 Resource's CLAIM10 and CLAIM30 audit values, respectively. As with a
22 Generator Asset, a Demand Response Resource will be able to request a
23 CLAIM10 and/or CLAIM30 audit, and each unannounced fast-start dispatch will

1 count towards its CLAIM10 and/or CLAIM30 calculation. And just as with
2 generators, the CLAIM10 or CLAIM30 value is adjusted by a performance factor
3 that increases or decreases the CLAIM10 or CLAIM30 value based on the
4 weighted average performance of the Demand Response Resource during the last
5 10 dispatches. As with Generator Assets, any dispatch in which a Demand
6 Response Resource goes out of service within 60 minutes results in a zero score
7 for that start in the performance factor calculation. Each resource providing 10- or
8 30-minute non-spinning reserves must audit at least once every Forward Reserve
9 Procurement Period.

10

11 A Demand Response Resource whose composition of Demand Response Assets
12 changes dramatically, or that operates infrequently, may be subject to increased
13 ISO-initiated CLAIM10/CLAIM30 auditing, as is true of Generator Assets.

14

15 **V. METERING, MEASUREMENT, AND VERIFICATION**

16 **Q: What revisions are being made to meter data certification requirements?**

17 A: The current rules require that Market Participants with Demand Response
18 Resources perform an annual independent certification of the accuracy and
19 precision of the meters, telemetry measurement devices, and data communication
20 systems used to provide data to the ISO. With the ability of Demand Response
21 Resources to provide Operating Reserve, however, the necessity for accurate
22 meter and telemetry data is heightened. The ISO therefore plans to replace the
23 annual certification process with an ongoing process that requires Market

1 Participants with Demand Response Resources to immediately notify the ISO of
2 any meter or telemetry accuracy problems. In addition, as is true today, issues
3 with metering, telemetry or data communication systems might also be revealed
4 during periodic analysis conducted by the ISO. Once an accuracy problem is
5 identified, the Market Participant must either indicate to the ISO when the issue(s)
6 will be resolved or it must retire any affected Demand Response Asset(s). In
7 addition, once such problems become known and until they are resolved, the
8 demand reduction capability of the affected Demand Response Asset(s) will be
9 excluded from the Demand Response Resource with which it is associated.

10

11 **Q: Please explain changes related to Measurement and Verification Plans.**

12 A: The performance of an Active Demand Capacity Resource is based on the
13 performance of its constituent Demand Response Resources (which, as noted, are
14 in turn based on the performance of their constituent Demand Response Assets).
15 Given that the revisions specify how the performance of Active Demand Capacity
16 Resources, Demand Response Resources, and Demand Response Assets is to be
17 determined, Active Demand Capacity Resources no longer need to submit
18 detailed Measurement and Verification Plans. Accordingly, the revisions
19 eliminate the existing measurement and verification rules, and the associated
20 qualification rules, as they apply to Active Demand Capacity Resources, but
21 retain them as they apply to passive Demand Capacity Resources (that is, to On-
22 Peak Demand Resources and Seasonal Peak Demand Resources).

23

1 **Q: Under the revisions, what data do Demand Response Resources submit on**
2 **days with forced or scheduled curtailments?**

3 A: A forced curtailment is a reduction in demand resulting from circumstances
4 outside the control of the Demand Response Asset or the Market Participant. A
5 scheduled curtailment is a reduction in demand resulting from a scheduled plant
6 shutdown or scheduled maintenance of energy consuming equipment. (Note that a
7 Demand Response Asset on a forced or scheduled curtailment is nevertheless
8 reducing demand, while a Generator Asset on a forced or scheduled outage is not
9 producing energy.) In either case, the metered demand of affected Demand
10 Response Assets is substantially lower than normal, and would result in a
11 distorted Demand Response Baseline if used in its computation.

12
13 To ameliorate the potential for baseline distortion, the current rules require that
14 Market Participants submit, for the duration of a curtailment, meter data that is
15 equal to the last unadjusted baseline of each affected Demand Response Asset.
16 However, under the software that will implement full integration, the baseline
17 calculation will be updated to automatically address any undue baseline distortion
18 from curtailments. With these revisions, Market Participants no longer need to
19 submit anything other than actual meter data for all days, which greatly simplifies
20 baseline administration for both Market Participants and the ISO.

21

1 **VI. OTHER**

2 **Q: Do the revisions make any changes to Real-Time Energy Market settlement?**

3 A: Yes, the revisions make a small change to the settlement rules. In Order No. 745,
4 the Commission required that the costs associated with demand response
5 compensation be allocated (billed) proportionally to all entities that purchase from
6 the energy market in the areas and at the time that demand resources are
7 committed or dispatched. The ISO complied by allocating payments resulting
8 from Real-Time demand reductions proportionally to Real-Time Load Obligation
9 on a system-wide basis, excluding Real-Time Load Obligation incurred at
10 External Nodes and by DARDs postured by the ISO. (When the ISO postures a
11 DARD Pump – that is, the load associated with the pumping phase of a pumped-
12 storage hydroelectric facility – the resource will pump (even though it is
13 uneconomic for it to do so at that time) because the ISO believes that the
14 hydroelectric generator associated with the DARD Pump will be needed to
15 provide energy later in the day.)

16

17 Upon further consideration, the ISO plans to expand the DARD exclusion to all
18 DARD Pumps, not just postured DARDs. Should Real-Time demand response
19 costs be billed to DARD Pumps, the Supply Offers of the associated pumped-
20 storage hydroelectric generators are likely to be higher to account for this cost,
21 and/or the Demand Bids of the DARD Pumps are likely to be lower, either of
22 which has the potential to distort the Real-Time Energy Market outcome,

1 potentially raising the price or reducing the quantity of stored energy in future
2 hours.

3
4 **Q: What is the baseline reset provision and why is it being eliminated?**

5 A: Under current rules, following a significant change in load, generation, or
6 reported meter data, the Demand Response Baseline of an existing Demand
7 Response Asset must be “reset,” that is, must be reestablished as though the Asset
8 were establishing a baseline for the first time. This baseline reset was initially
9 established because under the previous baseline methodology, the impact of bad
10 data on the baseline continued long after the bad data was submitted. However,
11 under the new 10-day rolling average baseline methodology accepted by the
12 Commission in 2015, the impact of any old or bad data on the calculated baseline
13 abates quickly, allowing the ISO to eliminate the complicated and somewhat
14 subjective baseline reset provision.

15
16 **Q: Please explain the revisions that implement Order No. 719’s directive to**
17 **forgive load’s deviation charges if, during a system emergency, it takes less**
18 **energy in Real-Time than was scheduled Day-Ahead.**

19 A: In Order No. 719, the Commission required ISOs to eliminate, during system
20 emergencies, deviation charges to buyers that take less electric energy in the Real-
21 Time market than they were scheduled to take Day-Ahead. In 2009, the ISO
22 submitted a filing to comply with this aspect of Order No. 719, but
23 implementation was deferred until Demand Response Resources were fully
24 integrated into the wholesale markets. The ISO’s Order No. 719 compliance

1 approach will therefore be implemented on June 1, 2018, along with full
2 integration. However, since several major market design changes have been made
3 since 2009, the ISO has reviewed its approach to this aspect of Order No. 719. I
4 describe the two revisions that were made as a result of that review below.

5
6 Under the ISO's initial approach, accepted by the Commission in 2010, the ISO
7 defined system emergencies, for the purpose of Order No. 719, as intervals in
8 which the ISO had dispatched demand resources or declared Operating Procedure
9 No. 4 (Action During a Capacity Deficiency) or Operating Procedure No. 7
10 (Action in an Emergency). During these system conditions, the ISO would not
11 allocate deviation charges to load that had taken less energy in Real-Time than
12 had been scheduled Day-Ahead. Instead, these deviation charges would be billed
13 to Real-Time Load Obligation in the Load Zone in which the NCPC charges
14 accrued.

15
16 The instant revisions update the conditions that are considered to be system
17 emergencies for purposes of this Tariff provision. Operating Procedures No. 4 and
18 No. 7 are retained under the revisions as system emergencies. However, the
19 dispatch of demand resources is eliminated as a system emergency given that the
20 demand resource types dispatched during Operating Procedure No. 4 (Real-Time
21 Demand Response Resources and Real-Time Emergency Generation Resources)
22 are eliminated from the Tariff as of June 1, 2018. In addition, Capacity Scarcity
23 Conditions (during which reserves are scarce), which are introduced on June 1,

1 2018 with the implementation of the Pay for Performance capacity market design,
2 are added to the list of system emergency conditions that trigger this deviation
3 reallocation Tariff provision.

4
5 These revisions also modify the allocation methodology for the deviation charges
6 not charged to load pursuant to this provision. Under the approach filed in April
7 2009, the NCPC costs not charged to load are billed only to the buyers located in
8 the same Load Zone as the buyer that reduced its energy usage – buyers in
9 another Load Zone affected by the same emergency condition who also benefited
10 (from improvements to system reliability and potentially lower LMPs) receive no
11 bill for reallocated NCPC costs. The revisions address this discrepancy by
12 allocating the NCPC costs not charged to load that reduced consumption to Real-
13 Time Load Obligation across all areas of the system affected by the emergency
14 condition.

15

16 **Q: Are there any revisions you have not discussed in your testimony?**

17 A: Yes. There are numerous straight-forward Tariff revisions that I have not
18 addressed in my testimony. For example, I have not addressed the numerous
19 defined terms that have been revised to incorporate demand response concepts
20 previously accepted by the Commission, nor have I addressed Tariff sections in
21 which demand response concepts previously accepted by the Commission are
22 added to parallel existing generator language (for example, the NCPC revisions to
23 Appendix F). There are also numerous non-substantive Tariff changes I do not

1 discuss, which clarify or correct the Tariff to, among other things, reflect the
2 intent of the market design, remove redundant or obsolete provisions, correct
3 inconsistent terminology and typographical errors, update the language with
4 newly defined terms, properly order existing Tariff sections, and correct internal
5 Tariff section references. All of these revisions are instead discussed in the filing
6 letter to which this Testimony is attached.

7

8 **Q: Does this conclude your testimony?**

9 A: Yes.

10

11 I declare under penalty of perjury that the foregoing is true and correct.

12

13 Executed on July 27, 2017

14



15

Henry Y. Yoshimura

16

I.2 Rules of Construction; Definitions

I.2.1 Rules of Construction:

In this Tariff, unless otherwise provided herein:

- (a) words denoting the singular include the plural and vice versa;
- (b) words denoting a gender include all genders;
- (c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;
- (d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;
- (e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;
- (f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;
- (g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;
- (h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;
- (i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;
- (j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

other late payment or charge, provided such payment is made on such next succeeding Business Day);

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

I.2.2. Definitions:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

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

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

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

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

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

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

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

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

Asset is a ~~generating unit~~ Generator Asset, ~~interruptible load~~, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, ~~demand response resource~~, a Dispatchable Asset Related Demand, or a ~~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 costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

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

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

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

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

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

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

Average Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

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

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

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

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 (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, as described in Section III.13.7.2.3 of Market Rule 1.

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

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

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

Capacity 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.13.7.5.1 of Market Rule 1.

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

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

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

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

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

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

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

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

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

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

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

Capacity Requirement is described in Section III.13.7.5.1 of Market Rule 1.

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

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in ~~Section III.13.7.2.1 of Market Rule 1, the rules filed with the Commission on January 17, 2014, and accepted by the Commission on May 30, 2014.~~

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

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

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

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

~~**Capacity Value** is the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.1.4.7 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.

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

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

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

Category 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 or the demand reduction capability of a Demand Response Resource.

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 the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

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

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

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

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

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

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

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

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

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

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Day-Ahead Demand Reduction Obligation is ~~defined in Section III.3.2.1(a) of Market Rule 1, 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, ~~purchase of demand reductions,~~ payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1 ~~and purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1.~~

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.1.10.1A(f)E2-6.

~~**Demand Reduction Value** is the quantity of reduced demand calculated pursuant to Section III.13.1.4.1.3 of Market Rule 1.~~

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: is a resource defined as Active Demand Response-Capacity Resources, On-Peak Demand Resources, ~~or and~~ Seasonal Peak Demand 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.E2 of Market Rule 1, or during Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours. 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 On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and 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.8.1.1~~~~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.8.~~2B~~.

~~**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-DRR Aggregation Zone that meets the~~ has been registered in accordance with Section III.8.1.2 ~~registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1.~~

Demand Response Resource Notification Time is the ~~period of minimum time, between from~~ the receipt of a startup Dispatch Instruction, ~~that it takes and the time the~~ a Demand Response Resource ~~that was not previously reducing demand to~~ starts reducing demand.

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

Demand Response Resource Start-Up Time is the period of time between~~required from~~ the time a Demand Response Resource ~~starts that was not previously~~ reducing demand at the conclusion of the Demand Response Resource Notification Time and starts reducing demand in response to a Dispatch Instruction and the time the resource can reach ~~achieves~~ its Minimum Reduction and be ready for further dispatch by the ISO.

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

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, 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 [Response](#) Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch 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. [12.4A13.1.4.6.1](#).

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.

DARD Pump is a Dispatchable Asset Related Demand that consists of all or part of the pumping load of a pumped storage generating Resource 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) is available for dispatch and manned or has automatic remote dispatch capability, and; (iv) is capable of receiving a start-up or shutdown Dispatch Instruction electronically.

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

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

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

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

Distributed Generation means generation 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 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 Capacity Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

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

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

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

~~**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 Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

Economic Minimum Limit or Economic Min is (a) for Resources with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for Resources without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design

characteristics of the Resource and with meeting all environmental regulations and licensing limits, and (c) for Resources undergoing Facility and Equipment Testing or auditing, the level to which the Resource requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

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

Effective Offer is the set of Supply Offer values (or **Demand Bid values** in the case of DARD Pumps) that are used for NCPC calculation purposes as specified in Section III.F.1.a.

EFT is electronic funds transfer.

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

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

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

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

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

transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

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

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

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

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

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

EMS is energy management system.

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

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

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

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

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

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

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

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

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

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

Energy Offer Floor is negative \$150/MWh.

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

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

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

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

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

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

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

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

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

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, 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 Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

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

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.~~1-12~~ of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

~~**Fast Start Generator** means a 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; and (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically.~~

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; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

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

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

Forward Capacity Auction (FCA) is the annual 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 \$9,000/megawatt-month.

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

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

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

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

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

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

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

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

Hourly PER is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

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

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

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

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

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

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

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

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(~~p~~^r) 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.

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

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

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

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

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

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

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

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

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

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

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

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

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

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

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

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

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

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

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

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

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.

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

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

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

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

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

Limited Energy Resource means 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 while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, chilled water storage, and other forms of electricity storage.

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

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

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

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

Local Area Facilities are defined in the TOA.

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

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

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

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

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

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

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

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

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System

Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

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

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

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

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

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

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

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

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub. ~~For Capacity Commitment Periods commencing on or after June 1, 2018, 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, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. ~~For Capacity Commitment Periods commencing on or after June 1, 2018, the Locational Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.~~

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

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

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

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

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

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

LSE means load serving entity.

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

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

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

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) of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or

exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is 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.

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

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 Demand Response 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 Demand Response Asset comprised of Distributed Generation.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that 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.

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 Number of Daily Starts is the maximum number of times that a DARD Pump or a generating Resource can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

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

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

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which 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 an On-Peak Demand Resource or Seasonal Peak 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 On-Peak Demand Resources or Seasonal Peak Demand Resources ~~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~~ demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource ~~supplier~~ with the monthly settlement report for the Forward Capacity Market, which documents the total ~~Demand Reduction Values~~ demand reduction capability for all On-Peak Demand Resources and Seasonal Peak Demand Resources in operation as of the end of the previous month.

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

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

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

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

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

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

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

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

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

Minimum Consumption Limit is 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 or DARD Pump has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or DARD Pump can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

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

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

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

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

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

Minimum Time Between Reductions is the ~~minimum~~ number of hours that ~~a Market Participant requires must elapse between the time the~~ after a Demand Response Resource ~~has received~~s a Dispatch Instruction ~~from the ISO to stop reducing not reduce~~ demand ~~and the time before~~ the Demand Response Resource ~~can achieve its Minimum Reduction after receiving receives~~ a Dispatch Instruction ~~from the ISO to start~~ ~~reducinge~~ demand.

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

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

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

Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

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

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

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

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

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

MUI is the market user interface.

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

MW is megawatt.

MWh is megawatt-hour.

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

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

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

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

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

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

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

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

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

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

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

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

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

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

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

Net CONE is an estimate of the Cost of New Entry, net of 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.13.7.5 of Market Rule 1.

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

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

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

Network Customer is a Transmission Customer receiving RNS or LNS.

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

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

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

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

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand [Capacity](#) Resource.

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

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

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

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

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

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

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.12 of Market Rule 1.

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

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

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

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

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

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

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

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

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

NMPTC means Non-Market Participant Transmission Customer.

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

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

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

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

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

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.1.3.

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

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

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

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

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

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

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

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

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

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

NPCC is the Northeast Power Coordinating Council.

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

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and 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 Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

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

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

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

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

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

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

Operations Date is February 1, 2005.

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

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

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

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

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a 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.

Passive DR Audit is the audit performed pursuant to [Section III.13.6.1.5.4.](#)

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

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

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

Peak Energy Rent (PER) is described in Section III.13.7.1.2 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.1.2.1 of Market Rule 1.

~~**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 Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone

Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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(~~de~~~~(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(~~if~~) of Market Rule 1.

Real-Time Demand Reduction Obligation is ~~defined in Section III.3.2.1(c) of Market Rule 1~~ ~~a Real-Time demand reduction amount determined pursuant to Section III.E2.7.~~

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

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

Real-Time Energy 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(~~ge~~) of Market Rule 1.

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

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

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(de)(iii) 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)(iv) of Market Rule 1.

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

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

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(de)(v) 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 Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

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

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

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

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

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

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTTA holder that sells, assigns or transfers its rights under its MGTTA, 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, an External Transaction or Demand Response Resource. For purposes of providing Regulation, Resource means a generating unit, a Dispatchable Asset Related Demand or an Alternative Technology Regulation Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission’s corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a 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 Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is ~~a seasonal the Demand Response Resource~~ audit ~~performed of the demand response capability of a Demand Resource initiated~~ pursuant to Section ~~III.1.5.1.3.1~~~~III.1.3.6.1.5.4.1.~~

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

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

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

Asset Related Demand would have been scheduled or dispatched by the ISO to consume Energy. Demand Response Resources are not permitted to Self-Schedule.

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

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

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

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

Start-Up Fee is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand [Capacity](#) Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

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

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

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

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources [pursuant to Section III.9](#). The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

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

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service

on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock; (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of (1) a generating Resource that can be converted fully into energy within ten minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO.

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

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

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

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

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

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

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total 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 On-Peak Demand Resource or Seasonal Peak Demand Response 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 [pursuant to Section III.9](#). The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

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

I.3 Obligations of Market Participants and Other Customers

The ISO acts as Counterparty for sales to its Customers of Regional Transmission Service, and for agreements and transactions with its Customers, including but not limited to assignments involving Customers, and agreements and transactions with Customers involving sale to the ISO and/or purchase from the ISO of energy, capacity, reserves, regulation, Ancillary Services, FTRs and involving other products, service and transactions, all as specified in Sections II and III of the Tariff (collectively, the “Products”).

To the extent permitted by applicable law, any warranties provided by the sellers or assignors to the ISO of the Products which cover the Products, whether express or implied, are hereby passed to the Customers on a “pass through basis” and to the extent not passed through, any such warranties are hereby assigned by ISO to Customers. Sellers and assignors to the ISO and Customers acknowledge that warranties on such Products are limited to that offered by the seller or assignor to the ISO and will exist, if at all, solely between the seller or assignor to the ISO and the Customer. AS BETWEEN CUSTOMER AND ISO AS COUNTERPARTY, NO EXPRESS OR IMPLIED WARRANTIES ARE MADE BY THE ISO REGARDING THE PRODUCTS SOLD BY THE ISO AS COUNTERPARTY, AND ANY SUCH PRODUCTS ARE PROVIDED ON AN “AS IS” AND “AS AVAILABLE” BASIS. THE ISO MAKES NO WARRANTY OR REPRESENTATION THAT THE PRODUCTS WILL BE UNINTERRUPTED OR ERROR FREE. THE CUSTOMER HEREBY WAIVES, AND THE ISO HEREBY DISCLAIMS, ALL OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING, WITHOUT LIMITATION, ANY WARRANTY OF MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, TITLE AND NON-INFRINGEMENT. THE ISO DOES NOT WARRANT THAT THE PRODUCTS OFFERED WILL MEET CUSTOMER’S REQUIREMENTS. NO ORAL OR WRITTEN INFORMATION OR ADVICE GIVEN BY THE ISO OR ANY AUTHORIZED REPRESENTATIVE OF THE ISO SHALL CREATE A WARRANTY OR IN ANY WAY INCREASE THE SCOPE OF ANY PASS THROUGH OR ASSIGNED WARRANTY. SOME JURISDICTIONS DO NOT ALLOW THE EXCLUSION OF IMPLIED WARRANTIES IN CERTAIN CIRCUMSTANCES, SO THE ABOVE EXCLUSION APPLIES ONLY TO THE EXTENT PERMITTED BY APPLICABLE LAW.

I.3.1. Service Agreement:

Receipt of service under this Tariff requires the execution of a Market Participant Service Agreement in the form specified in Attachment A or Attachment A-1, as applicable, to this Tariff unless the Customer seeks transmission service only and does not participate in the New England Markets (in which case the Customer must execute a Transmission Service Agreement). Receipt of Local Service under Section II of

this Tariff requires the execution of a Transmission Service Agreement in the form specified in Attachment A to Schedule 21 of Section II of this Tariff for Local Service and shall be subject to the requirements of Schedule 21. Receipt of OTF Service under Section II of this Tariff requires the execution of a Transmission Service Agreement in the appropriate form specified under Schedule 20 of Section II of this Tariff and shall be subject to the requirements of Schedule 20.

I.3.2. Assets:

Each Market Participant shall, to the fullest extent practicable, cause all of the Assets it owns or operates to be designed, constructed, maintained and operated in accordance with Good Utility Practice and the provisions of this Tariff, the ISO New England Operating Procedures, and the ISO New England Planning Procedures.

I.3.3. Maintenance and Repair:

Each Market Participant shall, to the fullest extent practicable: (a) cause Assets owned or operated by it to be withdrawn from operation for maintenance and repair only in accordance with maintenance schedules reported to, and approved and published by the ISO in accordance with the ISO New England Operating Procedures, (b) restore such Assets to good operating condition with reasonable promptness, and (c) in emergency situations, accelerate maintenance and repair at the reasonable request of the ISO in accordance with the ISO New England Planning Procedures.

I.3.4. Central Dispatch:

Each Market Participant shall, to the fullest extent practicable, subject each of the Assets it owns or operates to central dispatch by the ISO; provided, however, that each Market Participant shall at all times be the sole judge as to whether or not and to what extent safety requires that at any time any of such facilities will be operated at less than their full capacity.

I.3.5. Provision of Information:

The Customers shall provide the ISO with any and all information within their custody or control that the ISO deems necessary to perform its obligations under this Tariff, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. Each Customer shall ensure that the ISO has an accurate list of the Customer's Affiliates. The ISO will compile a list that shall be considered definitive. It will be the Customer's responsibility to regularly review the list and to promptly (and in advance of Affiliate changes, where possible) provide the ISO with additions and/or corrections to the list and, when requested, relevant supporting documentation.

I.3.6. Records and Information:

Each Customer shall keep such records as may reasonably be required by the ISO, and shall furnish to the ISO such records, reports and information (including forecasts) as it may reasonably require, provided that confidentiality thereof is protected in accordance with the ISO New England Information Policy.

I.3.7. Payment of Invoices; Compliance with Policies:

Each Customer is obligated to pay when due in accordance with this Tariff, the ISO New England Financial Assurance Policy and the ISO New England Billing Policy all amounts invoiced to it pursuant to this Tariff, and to comply with those terms, conditions and policies in all respects. If a Customer fails to meet the requirements specified in the ISO New England Financial Assurance Policy and ISO New England Billing Policy, the ISO may take such actions as are specified in those policies.

I.3.8. Protective Devices for Transmission Facilities:

Each Market Participant shall install, maintain and operate such protective equipment and switching, voltage control, load shedding and emergency facilities as the ISO and the applicable Transmission Owner may determine to be required in order to assure continuity of service and the stability of the New England Transmission System.

I.3.9. Review of Market Participant's Proposed Plans:

I.3.9.1 Submission and Review of Proposed Plan Applications:

Each Market Participant and Transmission Owner shall submit to the ISO, in such form, manner and detail as the ISO may reasonably prescribe, (i) any new or materially changed plan for additions to or changes to any generating and demand resources or transmission facilities rated 69 kV or above subject to control of such Market Participant or Transmission Owner, and (ii) any new or materially changed plan for any other action to be taken by the Market Participant or Transmission Owner, except for retirements of or reductions in the capacity of a generating resource or a demand resource, which may have a significant effect on the stability, reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant. No significant action (other than preliminary engineering action) leading toward implementation of any such new or changed plan shall be taken earlier than sixty days (or ninety days, if the ISO determines that it requires additional time to consider the plan and so notifies the Market Participant in writing within the sixty days) after the plan has been submitted to the ISO. Unless prior to

the expiration of the sixty or ninety days, whichever is applicable, the ISO notifies the Market Participant or Transmission Owner in writing that it has determined that implementation of the plan will have a significant adverse effect upon the reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant, the Market Participant or Transmission Owner shall be free to proceed. The ISO shall maintain on its website a list of such applications that are currently under review and the status of each such application. The ISO shall provide notice of any action taken with respect to any such applications, including an explanation of its reasons for such action, to each Market Participant or Transmission Owner as soon as reasonably practicable after such action is taken. The time limits provided by this section may be changed with respect to any such submission by agreement between the ISO and the Market Participant or Transmission Owner.

I.3.9.2 Additional Review of Additions of or Changes to Generating Resources:

Proposals for new generating resources or modifications to existing generating resources are also subject to the terms set out in Schedule 22, the Large Generator Interconnection Procedures and Agreement, and Schedule 23, the Small Generator Interconnection Procedures and Agreement, to Section II of the Tariff.

I.3.9.3 Reliability Review of Retirements of or Reductions in Capacity of an Existing Demand

Capacity Resource or Existing Generating Capacity Resource:

Proposals for the reduction of capacity from an Existing Demand Capacity Resource or an Existing Generating Capacity Resource below its Qualified Capacity amount for the relevant Capacity Commitment Period, including unit retirement, are reviewed for reliability impact pursuant to the terms set out in Section III.13.2.5.2.5 of the Tariff. Once a demand resource or generating resource has a cleared de-list bid pursuant to Section III of the Tariff it may reduce its capacity consistent with the terms of its de-list bid for all or any part of the Capacity Commitment Period of the approved de-list without further reliability review. However, any proposed physical modification to a de-listed generating facility must comply with the requirements, including the reliability review process, set out in Schedules 22 or 23, as applicable.

I.3.10. Market Participant to Avoid Adverse Effect:

If the ISO notifies a Market Participant pursuant to Section I.3.9.1 that implementation of the Market Participant's or Transmission Owner's plan has been determined to have a significant adverse effect upon the reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of one or more Market Participants,

the Market Participant or Transmission Owner shall not proceed to implement such plan unless the Market Participant (or the Non-Market Participant on whose behalf the Market Participant has submitted its plan) or Transmission Owner takes such action or constructs at its expense such facilities as the ISO determines to be reasonably necessary to avoid such adverse effect.

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-	<u>III.13.7.3.1</u>	<u>Monthly Stop-Loss.</u>
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	<u>III.13.7.5.1</u>	<u>Calculation of Capacity Requirement and Capacity Load Obligation.</u>
	<u>III.13.7.5.1.1</u>	<u>HQICC Used in the Calculation of Capacity Requirements.</u>
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	<u>III.13.7.35.3.4</u>	<u>Specifically Allocated CTRs Associated with Transmission Upgrades.</u>
	<u>III.13.7.35.3.5</u>	<u>[Reserved.]</u>
	<u>III.13.7.35.3.6</u>	<u>Specifically Allocated CTRs for Pool Planned Units.</u>
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III.13.8		Reporting and Price Finality.

III.13.8.1 Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto.

III.13.8.2 Filing of Forward Capacity Auction Results and Challenges Thereto.

III.14 Regulation Market.

III.14.1 Regulation Market System Requirements.

III.14.2 Regulation Market Eligibility.

III.14.3 Regulation Market Offers.

III.14.4 Regulation Market Administration.

III.14.5 Regulation Market Resource Selection.

III.14.6 Delivery of Regulation Market Products.

III.14.7 Performance Monitoring.

III.14.8 Regulation Market Settlement and Compensation.

III.14.9 Regulation Market Testing Environment.

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, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). 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, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as “Section III.1.4 Transactions,” and individually as a “Section III.1.4 Transaction.” Transactions that conform to the standards are referred to collectively as “Section III.1.4 Conforming Transactions,” and individually as a “Section III.1.4 Conforming Transaction.”

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

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

- (i) is not cleared or settled by the ISO as Counterparty;
- (ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

- (iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and
- (iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

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

- (i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;
- (ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and
- (iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

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

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

- (a) The following ~~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.

~~(ii)~~(iii) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.

~~(iii)~~(iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR Audit value.

- (b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.
- (c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.
- (d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.
- (e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

(a) An Establish Claimed Capability Audit may be performed only by a Generator Asset.

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

~~(c)~~ For a newly commercial Generator Asset:

- (i) An Establish Claimed Capability Audit will be scheduled by the ISO within ~~seven~~five Business Days of the commercial operation date for all Generator Assets except:
 - 1. Non-intermittent daily cycle hydro;
 - 2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
 - 3. Intermittent Generator Assets
- (ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
- (iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.

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

- (i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.
- (ii) An Establish Claimed Capability Audit shall be performed within ~~seven~~five Business Days of the date of the request.
- (iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
- (iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

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

~~(e)~~(f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays ~~Business Days~~ between 0800 and 2200.

~~(f)~~(g) 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.~~
- (i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.
- (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
- (iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.

~~(g)~~(h) 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
Hydraulic Turbine – Other	
Hydro-Conventional Daily Pondage	2
Hydro-Conventional Run of River	
Hydro-Conventional Weekly	
Wind	2
Photovoltaic	
Fuel Cell	
Energy Storage (Excludes Pumped Storage)	2

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

III.1.5.1.3. Seasonal Claimed Capability Audits.

~~(a)~~ A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.

~~(a)~~~~(b)~~ A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:

- (i) Non-intermittent daily hydro; and
- (ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

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

~~(c)~~~~(d)~~ Except as provided in Section III.1.5.1.3(~~nm~~) 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)~~~~(e)~~ A winter Seasonal Claimed Capability Audit must be conducted:

- (i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:
 - (1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.
 - (2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.
- (ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.

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

- (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the ~~fifth 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)~~(g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

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

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

~~(i)~~(j) 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
Hydraulic Turbine-Other	
Hydro-Conventional Weekly	2
Fuel Cell	1
Energy Storage (Excludes Pumped Storage)	2

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

- (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;
- (ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and
- (iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.

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

- (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;
- (ii) Retain the current Seasonal Claimed Capability Audit value for the season; and
- (iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.

(m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours

prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

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

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

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

III.1.5.1.3.1 Seasonal DR Audits.

(a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

(b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.

- (c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:
 - (i) At least once every Capability Demonstration Year;
 - (ii) During the months of April through November;
- (d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:
 - (i) At least once every Capability Demonstration Year;
 - (ii) During the months of December through March.
- (e) A Seasonal DR Audit may be performed either:
 - (i) At the request of a Market Participant as described in subsection (f) below; or
 - (ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.
- (f) If a Market Participant requests a Seasonal DR Audit:
 - (i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.
 - (ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.
 - (iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
 - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:
 - (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.
 - (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.
 - (iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.
 - (iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

- (h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.
- (i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.
- (j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.
- (k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.
- (l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.
- (m) The Seasonal DR Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.
- (o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

- (a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.
- (b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:

- (i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.
- (ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.
- (c) If for a Generator Asset a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.
- (d) ~~Establish Claimed Capability Audit~~ The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:
 - ~~(i) Notify the Designated Entity, immediately prior to issuing the Dispatch Instruction, that an audit will be conducted.~~
 - ~~(ii)(i)~~ (i) 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 or the Demand Response Resource to its Maximum Reduction.
 - ~~(ii)~~ (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - ~~(iii)~~ (iii) For Generator Assets, begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.
 - ~~(iii)(iv)~~ (iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
- (f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit
--

<u>Asset or Resource Unit Type</u>	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
Hydraulic Turbine – Other	
Hydro-Conventional Daily Pondage	2
Hydro-Conventional Run of River	
Hydro-Conventional Weekly	
Wind	2
Photovoltaic	
Fuel Cell	
Energy Storage (Excludes Pumped Storage)	2
<u>Demand Response Resource</u>	<u>1</u>

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

III.1.5.2 ISO-Initiated Parameter Auditing.

- (a) The ISO may perform an audit of any Supply Offer, Demand Reduction ~~o~~ffer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide real-time energy or reserves.
- (b) Generator audits shall be performed using the following methods for the relevant parameter:
- (i) **Economic Maximum Limit.** The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.
 - (ii) **Manual Response Rate.** The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.
 - (iii) **Start-Up Time.** The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.

- (iv) **Notification Time.** The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.
 - (v) **CLAIM10.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5.
 - (vi) **CLAIM30.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5.
 - (vii) **Automatic Response Rate.** The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.
 - (viii) **Dual Fuel Capability.** A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).
- (c) Demand Response Resource audits shall be performed using the following methods:
- (i) **Maximum Reduction.** The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.
 - (ii) **Demand Response Resource Ramp Rate.** The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.
 - (iii) **Demand Response Resource Start-Up Time.** The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.
 - (iv) **Demand Response Resource Notification Time.** The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.
 - (v) **CLAIM10.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5.
 - (vi) **CLAIM30.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5.
- (d) To conduct an audit based upon historical data, the ISO shall:
- (i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or

- (ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.
- (e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.
- (f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:
 - (i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.
 - (ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five ~~Business~~ ~~4~~Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.
- (g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.
- (h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:
 - (i) The Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:
 1. Provide an explanation of the discrepancy;
 2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
 3. Indicate the timeline for completing the restoration; and
 4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.
 - (ii) The ISO shall:
 1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;

2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

- (a) Two types of Reactive Capability Audits may be performed:
 - (i) A Lagging Reactive Capability Audit measures the Generator Asset's ability to provide reactive power to the transmission system at a specified real power output.
 - (ii) A Leading Reactive Capability Audit measures the Generator Asset's ability to absorb reactive power from the transmission system at a specified real power output.
- (b) The ISO shall develop a list of Generator Assets that must conduct Reactive Capability Audits.
- (c) Unless otherwise directed by the ISO, Generator Assets that are required to perform Reactive Capability Audits must perform both a Lagging Reactive Capability Audit and a Leading Reactive Capability Audit.
- (d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.
- (e) The Reactive Capability Audit value of a 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.
- (f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.
- (g) Reactive Capability Audits must be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Generator Asset to conduct Reactive Capability Audits more often than every five years if:
 - (i) there is a change in the Generator Asset that may affect the reactive power capability of the Generator Asset;
 - (ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Generator Asset; or
 - (iii) historical data shows that the amount of reactive power that the Generator Asset can provide to or absorb from the transmission system is higher or lower than the latest audit data.

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

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

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

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

III.1.7 **General.**

III.1.7.1 **Provision of Market Data to the Commission.**

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

III.1.7.2 [Reserved.]

III.1.7.3 **Agents.**

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

III.1.7.4 [Reserved.]

III.1.7.5 [Reserved.]

III.1.7.6 Scheduling and Dispatching.

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

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

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

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

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

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

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

III.1.7.7 Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

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

III.1.7.9 Real-Time Reserve Prices.

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

III.1.7.10 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 Seasonal DR Audit Value of an Active Demand Capacity Resource.

(a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.

(b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

~~[Reserved.]~~

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

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

III.1.7.18 [Reserved.]

III.1.7.19 Ramping.

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

III.1.7.19A Real-Time Reserve.

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

requirements for provision and dispatch of Operating Reserve capability as specified in Section III.10 and the ISO New England Manuals and ISO New England Administrative Procedures.

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

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

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

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

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

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

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

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

III.1.8 [Reserved.]

III.1.9 Pre-scheduling.

III.1.9.1 [Reserved.]

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 **Market Participant Responsibilities.**

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

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

- (a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.
- (b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.
- (c) In the Real-Time Energy Market,
- (i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and
 - (ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.
- (d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of generating ~~Resources-units or~~ Demand Response Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers ~~or Demand Reduction Offers 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) **Day-Ahead Locational Demand Bids** – Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resource increments, including hydropower units, Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the energy Supply Offer limitation specified in this Section.

(b) [Reserved.]

(c) **Day-Ahead External Transactions** – All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source

and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction submitted under Section III.1.10.7 and that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

- (i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;
- (ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;
- (iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;
- (iv) If the sum of all submitted fixed External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all fixed External Transaction sales at the applicable External Node shall be set equal to the Energy Offer Cap;
- (v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(d) **Day-Ahead Offers (Generator Assets and Dispatchable Asset Related Demand)** – Market Participants selling into the New England Markets, from either internal Resources (**other than Demand Response Resources**) or External Resources, shall submit Supply Offers or External Transactions for the

supply of energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Operating Reserve or other services as applicable, for the following Operating Day. (Coordinated External Transactions shall be submitted to the ISO in accordance with Section III.1.10.7.A of this Market Rule 1.)

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

- (i) Shall specify the Resource ~~or Load Asset~~ and energy for each hour of the Operating Day;
- (ii) Shall specify Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The price and quantity values in a Block may each vary on an hourly basis;
- (iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify, for Supply Offers, Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee values may vary on an hourly basis;
- (iv) For a dual fuel Resource, shall specify, for Supply Offers, the fuel type. The fuel type value may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual fuel Resources in Section III.A.3 of Appendix A;
- (v) Shall specify, for Supply Offers, a Minimum Run Time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;
- (vi) Supply Offers shall constitute an offer to submit the generating Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that for a Limited Energy Resource, the Economic Maximum Limit may be

revised to reflect maximum energy available for the Operating Day, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;

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

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

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

(e) ~~Reserved.~~ **Day-Ahead Offers (Demand Response Resources)** – Market Participants selling into the New England Markets from Demand Response Resources shall submit Demand Reduction Offers for the supply of energy, Operating Reserve or other services as applicable, for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The price and demand reduction quantity values may vary on an hourly basis.

(ii) Shall not specify a price that is above the Energy Offer Cap, below the Energy Offer Floor, or below the Demand Reduction Threshold Price in effect for the Operating Day. For

purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.

(f) ~~Reserved.~~ **Demand Reduction Threshold Price** – The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

(a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

- (b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.
- (c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.
- (d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.
- (e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th}X - \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the month preceding the Demand Reduction Threshold Price's effective date.

- (g) **Subsequent Operating Days** – Each Supply Offer, **Demand Reduction Offer**, or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Resource and an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer, **a Demand Reduction Offer**, or a Demand Bid shall remain in effect only for the applicable Operating Day.

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

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

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

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

- (l) **DARD Pumps** – DARD Pumps will not be scheduled below their Minimum Consumption Limits.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers or Demand Reduction Offers or, for DARDs, submitted Demand Bids to purchase, to sell energy in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as

generators, DARD Pumps or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

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

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

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

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

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

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. Demand Response Resources shall not be Self-Scheduled.

(a) The minimum duration of a Self-Schedule for a Generator Asset or DARD Pump shall not result in the Generator Asset or DARD Pump operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer. A DARD Pump that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid.

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

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

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

III.1.10.4 [Reserved.]

III.1.10.5 External Resources.

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

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

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

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

III.1.10.6 Dispatchable Asset Related Demand.

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 Market Participant with a Dispatchable Asset Related Demand 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 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's ability to respond to Dispatch Instructions 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; 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.

In addition to the requirements of (a) through (h) above, a Market Participant with a DARD Pump may submit Maximum Daily Consumption Limits, Maximum Number of Daily Starts, Minimum Down Time, and a Minimum Run Time that meet the following criteria:

- Maximum Daily Consumption Limits and Maximum Number of Daily Starts are only for use in the Day-Ahead Energy Market and may be redeclared in the Re-Offer Period;
- Minimum Run Time and Minimum Down Time may not exceed one hour each and may be changed through redeclaration requests.

III.1.10.7 External Transactions.

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

- (a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.
- (b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

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

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

(e) [Reserved.]

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

(i) Capacity Export Through Import Constrained Zone Transactions:

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

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

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

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

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

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

(ii) FCA Cleared Export Transactions:

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

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

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

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

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in

accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

- (1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;
- (2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;
- (3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;
- (4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

- (1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;
- (2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;
- (3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;

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

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

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

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

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

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

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges

described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

- (i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.
- (ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.
- (iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

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

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

III.1.10.7.A Coordinated External Transactions.

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

- (a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.
- (b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.
- (c) Interface Bids are cleared in economic merit order for each 15minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.
- (d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated NERC E-Tag at the time the transaction is submitted.
- (e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless applicable procedures governing the Emergency permit the transaction to be scheduled.

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

- (a) Background and Overview

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

If, pursuant to the timetables presented, the ISO determines the thresholds described herein have not triggered, the process for filing amendments to the ISO tariff as described herein ceases, the provisions of this Section III.1.10.7.B become null and void and the ISO will continue to implement Coordinated Transaction Scheduling unless and until future Section 205 filings are pursued to amend Coordinated Transaction Scheduling.

(b) The Two-Year Analysis

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

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

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

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

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

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

$$b/a$$

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

(c) Improving Coordinated Transaction Scheduling

- (1) If the ratio, developed pursuant to Section III.1.10.7.B(b)(1), is greater than 60% and b is greater than \$3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

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

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

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

(d) The Second Analysis

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

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

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

$$b/a$$

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

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

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

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

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

(e) The Compliance Filing

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

III.1.10.8 ISO Responsibilities.

(a) The ISO shall use its best efforts to determine (i) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement

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

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

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

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

III.1.10.9 Hourly Scheduling.

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

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

~~(c)~~ Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

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

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

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

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

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

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

request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

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

(g) 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.

(h) DARD Pumps will not be scheduled in Real-Time below their Minimum Consumption Limits.

III.1.11 Dispatch.

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

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource 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, consumption or demand reduction of Resource increments as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (c) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative

Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Dispatchable Resources.

With the exception of Settlement Only Resources, External Transactions, nuclear-powered Resources and photovoltaic Resources, all Resources must be Dispatchable Resources and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability. ~~Demand Response Resources are subject to additional dispatchability requirements as set forth in Appendix E2 to Market Rule 1.~~

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources are subject to the following requirements:

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

(b) The ISO shall implement the dispatch of energy from Dispatchable Resource increments and the designation of Real-Time Operating Reserve to Dispatchable 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. Each Market Participant shall ensure that the entity controlling a Dispatchable Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

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

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

(e) Intermittent Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind and hydro Intermittent Power Resources that are not Intermittent Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

(i) A wind or hydro Intermittent Power Resource not capable of receiving and responding to electronic Dispatch Instructions will be manually dispatched.

(ii) A Market Participant may elect, but is not required, to have a wind or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.

(iii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.

(f) The ISO may request that dual-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 Dispatchability Requirements for Intermittent Power Resources.

- (a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.
- (b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

III.1.11.6 Non-Dispatchable Resources.

Non-Dispatchable Resources are subject to the following requirements:

- (a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed and coordinates the testing pursuant to the

procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

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

III.2.2 General.

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

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

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

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

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

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

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

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

III.2.4 Adjustment for Rapid Response Pricing Assets.

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee, ~~or~~ No-Load Fee, or Interruption Cost is specified in the submitted Offer Data, a value of zero shall be used; if no Minimum Run Time, ~~or~~ minimum consumption time, or Minimum Reduction Time is specified in the submitted Offer Data, or if the submitted Minimum Run Time, ~~or~~ minimum consumption time, or Minimum Reduction Time is less than 15 minutes, a duration of 15 minutes shall be used; and the energy offer after adjustment shall not exceed the Energy Offer Cap.

(a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Dispatchable Asset Related Demand, its Minimum Consumption Limit shall be set to zero; if the Rapid Response Pricing Asset is a Fast Start Demand Response Resource, its Minimum Reduction shall be set to zero.

(b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.

(c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.

(d) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.

(e) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.

~~(f)~~ If the Rapid Response Pricing Asset is a Dispatchable Asset Related Demand that has not satisfied its minimum consumption time, its energy offer shall be decreased by: (i) the Start-Up Fee divided by the product of the Maximum Consumption Limit and the minimum consumption time; and (ii) the No-Load Fee divided by the Maximum Consumption Limit.

~~(g)~~ If the Rapid Response Pricing Asset is a Dispatchable Asset Related Demand that has satisfied its minimum consumption time its energy offer shall be decreased by the No-Load Fee divided by the Maximum Consumption Limit.

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, Demand Response Resources, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demand Resources with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply or consume 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.2.7A(c); and (5) the effect on transmission losses caused by the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

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

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

III.2.6 Calculation of Nodal Day-Ahead Prices.

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

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying an optimization method to minimize energy cost, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an

increment of load at each Node and External Node from each Resource associated with an eligible energy offer or bid as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Node.

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

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

- (i) All fixed External Transaction sales are considered to be dispatchable at the Energy Offer Cap;
- (ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply

Offer, [Demand Reduction 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-DRR Aggregation Zone](#) for both the Day-Ahead Energy Market and Real-Time Energy Markets using a load-weighted average of

the Locational Marginal Prices for the Nodes within that Load Zone ~~and or Dispatch-DRR Aggregation~~ Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and ~~DRR Aggregation 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 nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMNSR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

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

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-

Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the linear programming algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

<u>Requirement</u>	<u>Requirement Sub-Category</u>	<u>RCPF</u>
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 for every five-minute interval, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour.

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 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.~~

If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for the Real-Time Energy Market is five minutes and the settlement interval for the Day-Ahead Energy Market is hourly. The Real-Time Energy Market settlement is determined using the Metered Quantity For Settlement calculated in accordance with Section III.3.2.1.1.

(a) **Day-Ahead Energy Market Obligations** – For each Market Participant for each settlement interval, 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 settlement interval 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 settlement interval 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 Demand Reduction Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Demand Reduction Obligation at each Location equal to the MWhs of its Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market at that Location, increased by average avoided peak distribution losses. Day-Ahead Demand Reduction Obligations shall have a positive value.

(iv) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval 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.

(v) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation plus the Day-Ahead Demand Reduction Obligation at that Location.

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

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

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall

have positive value, provided by generating Resources, External Resources, and External Transaction purchases at that Location.

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

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

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

(c) **Real-Time Energy Market Obligations For Demand Response Resources**

Real-Time Demand Reduction Obligation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation at each Location equal to the MWhs of demand reduction provided by Demand Response Resources at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction produced by a Demand Response Resource are equal to the sum of the demand reductions produced by its constituent Demand Response Assets calculated pursuant to Section III.8.4, where the demand reductions, other than MWhs associated with Net Supply, are increased by average avoided peak distribution losses.

(d) **Real-Time Energy Market Deviations Excluding Demand Response Resource**

Contributions – For each Market Participant for each settlement interval, the ISO will determine the difference between the Real-Time Day-Ahead Energy Market position (calculated in accordance with

Section III.3.2.1(ba)) and the ~~Day-Ahead Real-Time~~ Energy Market position (calculated in accordance with Section III.3.2.1(ab)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

- (i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.
- (ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.
- (iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.
- (iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between (1) the Real-Time Locational Adjusted Net Interchange and (2) the Day-Ahead Locational Adjusted Net Interchange minus the Day-Ahead Demand Reduction Obligation for that Location.

(e) **Real-Time Energy Market Deviations For Demand Response Resources**

Real-Time Demand Reduction Obligation Deviation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(c)) and the Day-Ahead Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(a)). For purposes of this calculation, if the Real-Time settlement interval is less than

one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour.

(fd) **Day-Ahead Energy Market Charge/Credit** – For each Market Participant for each settlement interval, 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.

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

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

(h) **Real-Time Energy Market Charge/Credit For Demand Response Resources** – For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market associated with Demand

Response Resources. The charge or credit shall be equal to the sum of the Market Participant's Location-specific Real-Time Demand Reduction Obligation Deviations for that settlement interval multiplied by the Real-Time Locational Marginal Prices. Such charges and credits shall be allocated on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by DARD Pumps.

(if) **Day-Ahead and Real-Time Congestion Revenue** – For each settlement interval, 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 Deviation Congestion Charge/Credits.

(jg) **Day-Ahead Loss Revenue** – For each settlement interval, 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.

(kh) **Day-Ahead Loss Charges or Credits** – For each settlement interval 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(jg)). 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.

(li) **Real-Time Loss Revenue** – For each settlement interval, 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(ok) and Emergency transactions as described under Section III.4.3(a).

(m) Real-Time Loss Revenue Charges or Credits – 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.

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

(ok) Inadvertent Energy Revenue – For each External Node, for each settlement interval the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at the External Node by the associated Real-Time Locational Marginal Price. For each settlement interval, the total Inadvertent Energy Revenue for a settlement interval shall equal the sum of the Inadvertent Energy Revenue values for each External Node for that interval.

(pl) Inadvertent Energy Revenue Charges or Credits – 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(ok)). 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, and Real-Time Demand Reduction Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

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

III.3.2.1.1 Metered Quantity For Settlement.

For purposes of determining the Metered Quantity For Settlement, the five-minute telemetry value for a five-minute interval is the integrated value of telemetered data sampled over the five-minute period. For settlement calculations that require hourly revenue quality meter value from Resources that submit five-minute revenue quality meter data, the hourly revenue quality meter value is the average of five-minute revenue quality meter values for the hour. The Metered Quantity For Settlement is calculated as follows:

- (a) For external interfaces, the Metered Quantity For Settlement is the scheduled value adjusted for any curtailment, except that for Inadvertent Interchange, the Metered Quantity For Settlement is the difference between the actual and scheduled values, where the actual value is
 - (i) calculated as the five-minute telemetry value plus the difference between the hourly revenue quality meter value and the hourly average telemetry value, or
 - (ii) the five-minute revenue quality meter value, if five-minute revenue quality meter data are available.
- (b) For Resources submitting five-minute revenue quality meter data (other than Demand Response Resources), the Metered Quantity For Settlement is the five-minute revenue quality meter value.
- (c) For Resources with telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is calculated as follows:
 - (i) In the event that in an hour, the difference between the average of the five-minute telemetry values for the hour and the revenue quality meter value for the hour is greater than 20 percent of the hourly revenue quality meter value and greater than 10 MW then the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value, equally apportioned over the five-minute intervals in the hour.
 - (ii) Otherwise, the Metered Quantity For Settlement is the telemetry profile of the revenue quality meter value equal to the five-minute telemetry value multiplied by a scale factor, where the scale factor is the hourly revenue quality meter value divided by the hourly average telemetry value.
- (d) For a Demand Response Resource, the Metered Quantity For Settlement equals the sum of the demand reductions of each of its constituent Demand Response Assets produced in response to a non-zero Dispatch Instruction, with the demand reduction for each such asset calculated pursuant to Section III.8.4.

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(e) For Resources without telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour.

~~For purposes of determining the Metered Quantity For Settlement, the five-minute telemetry value for a five-minute interval is the integrated value of telemetered data sampled over the five-minute period. For settlement calculations that require hourly revenue quality meter value from Resources that submit five-minute revenue quality meter data, the hourly revenue quality meter value is the average of five-minute revenue quality meter values for the hour.~~

III.3.2.2 Metering and Communication.

(a) Revenue Quality Metering and Telemetry for Assets other than Demand Response Assets

The megawatt-hour data of each Generator Asset, Tie-Line Asset, and Load Asset must be metered and automatically recorded at no greater than an hourly interval using metering located at the asset's point of interconnection, in accordance with the ISO operating procedures on metering and telemetering. This metered value is used for purposes of establishing the hourly revenue quality metering of the asset.

The instantaneous megawatt data of each Generator Asset (except Settlement Only Resources) and each Dispatchable Asset Related Demand must be automatically recorded and telemetered in accordance with the requirements in the ISO operating procedures on metering and telemetering.

(b) Meter Maintenance and Testing for all Assets

Each Market Participant must adequately maintain metering, recording and telemetering equipment and must periodically test all such equipment in accordance with the ISO operating procedures on metering and telemetering. Equipment failures must be addressed in a timely manner in accordance with the requirements in the ISO operating procedures on maintaining communications and metering equipment.

(c) Additional Metering and Telemetry Requirements for Demand Response Assets

- (i) Market Participants must report to the ISO in real time a set of telemetry data for each Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of Demand Response Assets as measured at their Retail Delivery Points, and shall be reported to the ISO every five minutes. For a Demand Response Resource to provide TMSR or TMNSR, 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.

- (ii) 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 electrically 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 meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.
- (iii) If the Market Participant or the ISO finds that the metering or telemetry devices do not meet the accuracy requirements specified in the ISO New England Manuals and Operating Procedures, the Market Participant shall promptly notify the ISO and indicate when it expects to resolve the accuracy problem(s), or shall request that the affected Demand Response Assets be retired. Once such an issue becomes known and until it is resolved, the demand reduction value and Operating Reserve capability of any affected Demand Response Asset shall be excluded from the Demand Response Resource with which it is associated.
- (iv) The ISO may 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.

(de) Overuse of Flat Profiling

In the event a Market Participant's telemetry is replaced with an hourly flat profile pursuant to Section III.3.2.2.1(b) more than 20% of the online hours in a month and Market Participant's Resource has been online for over 50 hours in the month, the ISO may consult with the Market Participant for an explanation

of the regular use of flat profiling and may request that the Market Participant address any telemetry discrepancies so that flat profiling is not regularly triggered.

Within 10 business days of issuance of such a request, the Market Participant shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for completing such remediation. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan.

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) For each settlement interval during an hour in which there are Emergency Energy purchases, the ISO calculates an Emergency Energy purchase charge or credit equal to the Emergency Energy purchase price minus the External Node Real-Time LMP for the interval, multiplied by the Emergency Energy quantity for the interval. The charge or credit for each interval in an hour is summed to an hourly value. The ISO allocates the hourly charges or credits 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. Generating Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs or credits attributable to the purchase of Emergency Energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) For each settlement interval during an hour in which there are Emergency Energy sales, the ISO calculates Emergency Energy sales revenue, exclusive of revenue from the Real-Time Energy Market, received from other Control Areas to provide the Emergency Energy sales. The revenues for each interval in an hour is summed to an hourly value. Hourly net revenues 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. Generating Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency Energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

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

III.3.2.7 Billing.

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

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

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

III.3.4.2 Transmission Losses.

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

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting.

Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 **Data Reconciliation.**

III.3.6.1 **Data Correction Billing.**

The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 **Eligible Data.**

The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily Coincident Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 **Data Revisions.**

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines [specified in the ISO New England Manuals](#) 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. Errors in telemetry values used in calculating Metered Quantity For Settlement are not eligible for correction under this Section III.3.8.

(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.7 Financial Transmission Rights Auctions

III.7.1 Auctions of Financial Transmission Rights.

Periodic auctions (“FTR Auctions”) to allow Eligible FTR Bidders to acquire or FTR Holders to sell FTRs shall be conducted by the ISO in accordance with the provisions of this Section. Non-Market Participants that want to participate in the FTR Auction and have satisfied the applicable financial assurance criteria will be charged a one time FTR Registration Fee of \$5,000.

III.7.1.1 Auction Period and Scope of Auctions.

- (a) FTR Auctions shall be held on an annual and monthly basis.

- (b) The annual FTR Auction shall be conducted for FTRs effective for a single calendar year in two sequential rounds. Twenty-five percent of the available network capacity shall be available for the initial round of the annual FTR Auction. The FTRs that remain feasible with fifty percent of the network capacity available and after deducting the network capability associated with FTRs sold in the initial round shall be made available during the second round of the annual FTR Auction.

- (c) The ISO shall conduct monthly FTR Auctions, after the completion of the annual FTR Auction, every month. FTRs shall be made available for monthly auctions as follows:
 - (i) When FTRs for a month are auctioned, all FTRs that remain feasible will be made available, after accounting for all FTRs transacted in the annual FTR Auctions.

III.7.1.2 FTR Auctions Assumptions.

For annual FTR Auctions, the auction assumptions, including the modeling assumptions to be used for the FTR Auctions and dates and times for the opening and closing of bid submission windows will be announced by the ISO no later than 90 days prior to the first effective day of the FTRs to be auctioned. For monthly FTR Auctions, the auction assumptions, including the modeling assumptions to be used for the FTR Auctions and dates and times for the opening and closing of bid submission windows will be announced by the ISO no later than 40 days prior to the first effective day of the FTRs to be auctioned.

III.7.2 Financial Transmission Rights Characteristics.

III.7.2.1 Reconfiguration of Financial Transmission Rights.

Using an appropriate linear programming model, the ISO shall reconfigure the FTRs offered or otherwise available for sale in any auction to maximize the value to the bidders of the FTRs sold, provided that any FTRs acquired at auction shall be simultaneously feasible in combination with those FTRs outstanding at the time of the auction and not sold in the auction. The linear programming model shall, while respecting transmission constraints and the maximum megawatt quantities of the bids and offers, select the set of simultaneously feasible FTRs with the highest total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers.

III.7.2.2 Specified Locations.

Auction bids for FTRs may specify any combination of receipt and delivery locations represented in the State Estimator model for which the ISO calculates and posts Locational Marginal Prices. Auction bids may specify receipt and delivery points from locations outside of the New England Control Area to locations inside the New England Control Area, from locations within the New England Control Area to locations outside of the New England Control Area, or to and from locations within the New England Control Area. Congestion over interfaces associated with non-PTF external tie lines is not subject to LMP-based congestion management and, therefore, no FTRs across such interfaces will be included in the FTR Auctions.

III.7.2.3 Transmission Congestion Revenues.

FTRs shall entitle holders thereof to credits only for Transmission Congestion Revenue, and shall not confer a right to credits for payments arising from or relating to transmission congestion made to any entity other than the ISO.

III.7.2.4 [Reserved.]

III.7.3 Auction Procedures.

III.7.3.1 Role of the ISO.

FTRs auctions shall be conducted by the ISO in accordance with standards and procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures, such standards and procedures to be consistent with the requirements of this Market Rule.

III.7.3.2 [Reserved.]

III.7.3.3 [Reserved.]

III.7.3.4 On-Peak and Off-Peak Periods.

The ISO will conduct separate auctions simultaneously for on-peak and off-peak periods. On-peak FTRs shall cover the periods from 7:00 a.m. up to the hour ending at 11:00 p.m. on Mondays through Fridays, except holidays as defined in the ISO New England Manuals and ISO New England Administrative Procedures. Off-peak FTRs shall cover the periods from 11:00 p.m. up to the hour ending 7:00 a.m. on Mondays through Fridays and all hours on Saturdays, Sundays, and NERC holidays as defined in the ISO New England Manuals and ISO New England Administrative Procedures. Each bid shall specify whether it is for an on-peak or off-peak period.

III.7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase FTRs shall be submitted during the applicable period set forth in Section III.7.1.2, and shall be in the form specified by the ISO in accordance with the requirements set forth below.

(b) Offers to sell shall identify the specific FTRs, by megawatt quantity and receipt and delivery points, offered for sale. An offer to sell a specified megawatt quantity of FTRs shall constitute an offer to sell a quantity of FTRs equal to or less than the specified quantity. An offer to sell may not specify a minimum quantity being offered. Each offer may specify a reservation price, below which the offeror does not wish to sell the FTR. Offers shall be subject to such applicable standards for the financial assurance of the offeror or for the posting of security for performance as the ISO shall establish.

(c) Bids to purchase shall specify the megawatt quantity, price per megawatt, and receipt and delivery points of the FTR that the bidder wishes to purchase. A bid to purchase a specified megawatt quantity of FTRs shall constitute a bid to purchase a quantity of FTRs equal to or less than the specified quantity. A bid to purchase may not specify a minimum quantity that the bidder wishes to purchase. A bid may specify as receipt or delivery points any Location for which the ISO calculates and posts Locational Marginal Prices in accordance with Section III.2 of this Market Rule and may include FTRs for which the associated Transmission Congestion Credits may have negative values. Bids shall be subject to such applicable standards for the financial assurance of the bidder or for the posting of security for performance as the ISO shall establish.

(d) Bids and offers shall be specified to the nearest 0.1 megawatt and the quantity shall be greater than zero.

III.7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of each bidding period, the ISO will create a base FTR power flow model that includes all outstanding FTRs that have previously been awarded for the period for which the auction was conducted and that were not offered for sale in the auction. The base FTR model for the annual FTR Auction will reflect the network topology and transmission operating limits in effect at the time the annual FTR Auction is conducted, adjusted for estimated scheduled transmission outages. Monthly FTR Auctions shall utilize the then current network topology and transmission operating limits, as adjusted for currently estimated scheduled transmission outages and outages of individual generating units to the extent that such outages impact voltage or stability limits. The base FTR models also will include estimated uncompensated parallel flows into each interface point of the New England Control Area.

(b) In accordance with the requirements of this Section and subject to all applicable transmission constraints and reliability requirements, the ISO shall determine the simultaneous feasibility of all outstanding FTRs not offered for sale in the auction and of all FTRs that could be awarded in the auction for which bids were submitted. The winning bids shall be determined from an appropriate linear programming model that, while respecting transmission constraints and the maximum megawatt quantities of the bids and offers, selects the set of simultaneously feasible FTRs with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected FTRs and there are insufficient FTRs to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the FTRs that can be awarded.

(c) FTRs shall be sold at the market-clearing price for FTRs between specified pairs of receipt and delivery points, as determined by the bid value of the marginal FTR that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all FTR paths based on the bid value of the marginal FTRs, which are those FTRs with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each FTR's path relative to the marginal FTRs' paths flow sensitivities on the binding transmission constraints.

III.7.3.7 Announcement of Winners and Prices.

(a) After the close of the first round of the annual FTR Auction, in accordance with the schedule published in the auction assumptions and prior to the open of the bidding window for the final-round annual auctions, the ISO shall post the auction prices and FTRs cleared between eligible bidding

locations, as specified in Section III.7.2.2, excluding the identity of the winning bidder. The identities of winning bidders and the quantities of FTRs cleared by individual bidders in the first round of the annual auction will not be published until the close of the final round of the annual FTR Auction.

After the close of the final round of the annual FTR Auction, the ISO shall post, in accordance with the schedule set forth in the auction assumptions and prior to the open of the bidding window for monthly auctions, the winning bidders, the megawatt quantity, and the receipt and delivery points for each FTR awarded in the annual auction and the price at which each FTR was awarded.

(b) After the close of the monthly FTR Auction process, in accordance with the schedule set forth in the auction assumptions and prior to the effective date of the auctioned FTRs, the ISO shall post the winning bidders, the megawatt quantity, and the receipt and delivery points for each FTR awarded in the auction and the price at which each FTR was awarded. The FTR awards and prices shall be final as posted and not subject to correction or other adjustment, and shall be used for purposes of settlement, except as provided in subsections (d) and (e).

(c) Before posting the final FTR awards and prices, the ISO shall make a good faith effort when clearing the FTR Auction to discover and correct any errors that may occur due to database, software or similar errors of the ISO or its systems.

(d) If the ISO determines based on a reasonable belief that there may be one or more errors in the final FTR awards and prices or if no FTR awards or prices 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 applicable posting deadlines specified in subsections (a) or (b), as appropriate, a notice that the FTR awards and prices 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 FTR awards and prices and shall post a notice stating its findings.

(e) Within three business days after posting an initial notice pursuant to subsection (d); the ISO shall either: (1) publish final or corrected FTR awards and prices, or (2) in the event that the ISO is unable to calculate and post final or corrected FTR awards and prices 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 FTR awards and prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

(f) Results of the on-peak auction and off-peak auction will be posted separately. The ISO shall not disclose the price specified in any bid to purchase or the reservation price specified in any offer to sell.

III.7.3.8 Auction Settlements.

All buyers and sellers of FTRs between the same points of receipt and delivery shall pay or be paid the market-clearing price, as determined in the auction, for such FTRs.

III.7.3.9 Allocation of Auction Revenues.

All auction revenues, net of payments to entities selling FTRs into the auction, shall be allocated as specified under Appendix C of this Market Rule.

III.7.3.10 Simultaneous Feasibility.

The ISO shall make the simultaneous feasibility determinations specified herein using appropriate power flow models of contingency-constrained dispatch. Such determinations shall take into account outages, network model-related changes, and expected configuration of transmission facilities in accordance with Section III.7.3.6(a). The goal of the simultaneous feasibility determination shall be to ensure that there are sufficient Transmission Congestion Revenues to satisfy all FTR obligations for the auction period under expected conditions.

III.7.3.11 [Reserved.]

III.7.3.12 Financial Transmission Rights in the Form of Options.

When the ISO has the necessary software and hardware, the FTR Auctions shall allow for the acquisition of FTRs that do not create potential obligations to pay.

~~III.8 Demand Response Baselines~~

III.8 Additional Requirements for Demand Response **Assets** and Demand Response **Resources**

III.8.1 Registration and Aggregation

III.8.1.1 Demand Response Asset Registration and Aggregation

- (a) A Demand Response Asset must have a Maximum Interruptible Capacity of at least 10 kW.
- (b) A Demand Response Asset must have a single Retail Delivery Point and be registered at a single Node, unless it meets the conditions for aggregation in Section III.8.1(e).
- (c) No more than one Demand Response Asset may be registered at a Retail Delivery Point.
- (d) A Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.
- (e) A Demand Response Asset may be the aggregate demand reduction capability of multiple end-use customers with multiple Retail Delivery Points within a single DRR Aggregation Zone if (i) the demand reduction from each Retail Delivery Point is less than 10 kW and (ii) the demand at all Retail Delivery Points represents a homogeneous population as determined by the ISO. A Demand Response Asset that meets these conditions for aggregation must be registered at a DRR Aggregation Zone.
- (f) A Demand Response Asset with a Maximum Interruptible Capacity equal to or greater than 5 MW at a single Retail Delivery Point must be registered as a single Demand Response Resource at a single Node.
- (g) The metering and communication equipment associated with each Demand Response Asset must meet the requirements in Section III.3.2.2 and ISO New England Operating Procedure No. 18, Metering and Telemetry Criteria.
- (h) Upon request, the ISO will inform a load serving entity if (i) any of its end-use customers' facilities are registered as Demand Response Assets and (ii) the load reduction capability of any such Demand Response Assets.

III.8.1.2 Demand Response Resource Registration and Aggregation

- (a) A Demand Response Resource must be comprised of one or more Demand Response Assets within the same DRR Aggregation Zone.

- (b) A Demand Response Resource must be capable of at least 0.1 MW of demand reduction.
- (c) A Demand Response Resource cannot be comprised of: (i) 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 reduction capability to be bid into the ISO-administered markets or programs or (ii) 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 reduction capability to be bid into the ISO-administered markets or programs.
- (d) Each Demand Response Resource registered by a Market Participant within a single DRR Aggregation Zone must have a demand reduction capability of at least 1 MW before the Market Participant registers a new Demand Response Resource within the same DRR Aggregation Zone, unless either:
- (i) all the Demand Response Resources registered by the Market Participant in the DRR Aggregation Zone are associated with an Active Demand Capacity Resource and the Market Participant wishes to register a Demand Response Resource that is not; or
- (ii) none of the Demand Response Resources registered by the Market Participant in the DRR Aggregation Zone are associated with an Active Demand Capacity Resource and the Market Participant wishes to register a Demand Response Resource that is.
- (e) If the Seasonal DR Audit value of a Demand Response Resource falls below 1 MW causing a Market Participant to have more than one Demand Response Resource in a single DRR Aggregation Zone with a Seasonal DR Audit value less than 1 MW, then that Market Participant must reassign its Demand Response Assets if doing so decreases the number of that Market Participant's Demand Response Resources within that DRR Aggregation Zone, unless either:
- (i) the Demand Response Resource with a Seasonal DR Audit value less than 1 MW is associated with an Active Demand Capacity Resource and the other of the Market Participant's Demand Response Resources are not; or
- (ii) the Demand Response Resource with a Seasonal DR Audit value less than 1 MW is not associated with an Active Demand Capacity Resource and the other of the Market Participant's Demand Response Resources are.

III.8.2 Demand Response Baselines

- (a) A Demand Response Baseline is calculated for each Demand Response Asset for the following three day types:
- (i) weekdays (excluding Demand Response Holidays);

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(ii) Saturdays; and

(iii) Sundays and Demand Response Holidays.

(b) A Market Participant shall not take any action to create or maintain a Demand Response Baseline that exceeds the typical electricity consumption levels of its end-use metered customers expected in the normal course of business.

(c) A Market Participant may not submit Demand Reduction Offers for a Demand Response Resource for a given Operating Day unless a baseline for that day type for at least one Demand Response Asset assigned to the Demand Response Resource was established at least two calendar days prior to that Operating Day.

(d) If a Demand Response Asset produces Net Supply in an interval, that Net Supply will be used in the Demand Response Baseline calculations for that interval.

III.8.2.1 Determining the Weekday Non-Holiday Demand Response Baseline

A Demand Response Asset's weekday (non-Demand Response Holiday) Demand Response Baseline in each five-minute interval is equal to the average of the asset's meter data for the same five-minute interval from 10 prior non-Demand Response Holiday weekdays, as follows:

- (a) For a Demand Response Asset without a weekday Demand Response Baseline, the initial weekday Demand Response Baseline will be created using meter data from the first 10 consecutive non-Demand Response Holiday weekdays with a complete set of five-minute interval meter data.
- (b) For a Demand Response Asset that has established a weekday Demand Response Baseline, the baseline will be updated using meter data from:
 - (i) the 10 most recent of the previous 30 non-Demand Response Holiday weekdays, excluding days during which: (1) the resource associated with the asset received a Dispatch Instruction for an amount greater than 0 MW or (2) the asset was on a forced or scheduled curtailment as described in Section III.8.3;
 - (ii) if there are fewer than 10 such days, then meter data from additional days will be used (until a total of 10 days have been identified) including, first, the most recent days during which the resource associated with the asset received a Dispatch Instruction for an amount greater than 0 MW and, second, the most recent days during which the asset was on a forced or scheduled curtailment as described in Section III.8.3.

III.8.2.2 Determining the Saturday Demand Response Baseline

A Demand Response Asset's Saturday Demand Response Baseline in each five-minute interval is equal to the average of the asset's meter data for the same five-minute interval from five prior Saturdays as follows:

- (a) For a Demand Response Asset without a Saturday Demand Response Baseline, the Saturday Demand Response Baseline will be created using meter data from the first five consecutive Saturdays with a complete set of five-minute interval meter data.
- (b) For a Demand Response Asset that has established a Saturday Demand Response Baseline, the baseline will be updated using meter data from:
 - (i) the five most recent Saturdays of the previous 42 calendar days, excluding Saturdays during which: (1) the resource associated with the asset received a Dispatch Instruction for an amount greater than 0 MW or (2) the asset was on a forced or scheduled curtailment as described in Section III.8.3.
 - (ii) if there are fewer than five such Saturdays, then, in addition to those days, meter data from the most recent Saturdays will be used, until five days are identified.

III.8.2.3 Determining the Sunday and Demand Response Holiday Demand Response Baseline

A Demand Response Asset's Sunday and Demand Response Holiday Demand Response Baseline in each five-minute interval is equal to the average of the asset's meter data for the same five-minute interval from five prior Sundays or Demand Response Holidays as follows:

- (a) For a Demand Response Asset without a Sunday and Demand Response Holiday Demand Response Baseline, the Sunday and Demand Response Holiday Demand Response Baseline will be created using meter data from the first five consecutive Sundays and Demand Response Holidays with a complete set of five-minute interval meter data.
- (b) For a Demand Response Asset that has established a Sunday and Demand Response Holiday Demand Response Baseline, the baseline will be updated using meter data from:
 - (i) the five most recent Sundays or Demand Response Holidays of the previous 42 calendar days, excluding Sundays or Demand Response Holidays during which: (1) the resource associated with the asset received a Dispatch Instruction for an amount greater than 0 MW or (2) the asset was on a forced or scheduled curtailment as described in Section III.8.3;

(ii) if there are fewer than five such Sundays or Demand Response Holidays, then, in addition to those days, meter data from the most recent Sunday or Demand Response Holiday will be used, until five days are identified.

III.8.2.4 Demand Response Baseline Adjustment

- (a) The ISO will calculate an adjustment to the Demand Response Baseline of a Demand Response Asset in each interval in which its associated Demand Response Resource receives a non-zero Dispatch Instruction. The adjustment can result in a higher or lower Demand Response Baseline during the dispatch.
- (b) The adjustment is equal to the average megawatt difference between the Demand Response Asset's metered demand (which may reflect Net Supply) and its Demand Response Baseline during the three most recently completed five-minute intervals prior to the issuance of the start-up instruction; provided that, if there was a non-zero Dispatch Instruction during any of those three five-minute intervals, the adjustment during the current dispatch will equal the adjustment during the prior dispatch.
- (c) For Demand Response Assets that cannot produce Net Supply, the adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load.
- (d) For Demand Response Assets that can produce Net Supply, the adjusted Demand Response Baseline shall not be less than (that is, shall not result in output at the Retail Delivery Point that exceeds) the maximum megawatt amount approved in the applicable Interconnection Agreement and shall not exceed the asset's Maximum Facility Load.

III.8.3 Demand Response Asset Forced and Scheduled Curtailments

In addition to complying with the outage requirements described in ISO New England Operating Procedure No. 5, a Market Participant with a Demand Response Asset must abide by the following curtailment procedures.

- (a) Forced Curtailment – A Market Participant with a Demand Response Asset may notify the ISO of a forced curtailment, that is, a reduction in demand resulting from actions outside the control of the Demand Response Asset or the Market Participant subject to the forced curtailment.
- (b) Scheduled Curtailment – At least seven calendar days prior to the start of the curtailment, a Market Participant with a Demand Response Asset may notify the ISO of a scheduled curtailment, that is, a reduction in demand resulting from a scheduled plant shutdown or scheduled maintenance of energy consuming equipment. A scheduled curtailment may be no

shorter than a single calendar day and the total duration of scheduled curtailments per Capacity Commitment Period may not exceed 14 calendar days.

- (c) Offers and Settlement – Except for the first day of a forced curtailment, (i) Demand Reduction Offer parameters may not include any contributions from a Demand Response Asset on a forced or scheduled curtailment and (ii) a Demand Response Asset on a forced or scheduled curtailment shall not be eligible for payment in the Real-Time Energy Market.

III.8.4 Demand Response Asset Energy Market Performance Calculations

- (a) The ISO will calculate the demand reduction contribution of a Demand Response Asset in each interval in which its associated Demand Response Resource has received a non-zero Dispatch Instruction following the conclusion of the Demand Response Resource Notification Time. The demand reduction contribution by a Demand Response Asset to its Demand Response Resource shall equal the difference between the adjusted Demand Response Baseline of the Demand Response Asset and the metered demand of the Demand Response Asset, except as follows:
- (i) On the first day of a forced curtailment, a Demand Response Asset's demand reduction shall equal the difference between the unadjusted Demand Response Baseline of the Demand Response Asset and the metered demand of the Demand Response Asset; and
- (ii) A Demand Response Asset shall be assessed a zero demand reduction on any day of a forced curtailment other than the first day; on any day of a scheduled curtailment; in any interval in which there is insufficient data to calculate the Demand Response Baseline; and in any interval in which the Market Participant fails to comply with the Demand Response Asset metering and communication requirements in Section III.3.2.2 or ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.
- (b) Notwithstanding the foregoing, an Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be calculated pursuant to Section III.13.7.2.2.

~~III.8B~~ ~~————~~ ~~Demand Response Baselines~~

~~A Demand Response Baseline is calculated in five-minute intervals for each Demand Response Asset that is metered at the Retail Delivery Point for the following three-day types:~~

- ~~(a) weekdays (excluding Demand Response Holidays);~~
- ~~(b) Saturdays; and~~
- ~~(c) Sundays and 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, III.8B.3, and III.8B.4.~~

~~————~~ ~~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 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 occurs.~~

~~For a weekday (excluding Demand Response Holidays) day type, the initial Demand Response Baseline, or reset of a Demand Response Baseline, for each five-minute interval shall be the simple average of meter data for the asset for the same five-minute interval, subject to the conditions in Section III.8B.1, from the first 10 consecutive weekdays (excluding Demand Response Holidays) with a complete set of interval meter data.~~

~~For a Saturday day type, the initial Demand Response Baseline, or a reset of a Demand Response Baseline, for each five-minute interval shall be the simple average of meter data for the asset for the same five-minute interval, subject to the conditions in Section III.8B.1, from the first five consecutive Saturdays with a complete set of interval meter data.~~

~~For a Sunday and Demand Response Holiday day type, the initial Demand Response Baseline, or a reset of a Demand Response Baseline, for each five-minute interval shall be the simple average of meter data for the asset for the same five-minute interval, subject to the conditions in Section III.8B.1, from the first five consecutive Sundays and Demand Response Holidays 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 in a given month unless the initial baseline for that day type for at least one Demand Response Asset mapped to the Demand Response Resource was established at least seven calendar days prior to the first day of that month. This condition applies when establishing an initial Demand Response Baseline but not when resetting a Demand Response Baseline.~~

~~**8B.3 — Determining the Meter Data Used to Calculate the Demand Response Baseline for a Weekday (excluding Demand Response Holidays) Day Type**~~

~~For a Demand Response Asset that has established an initial Demand Response Baseline for weekdays (excluding Demand Response Holidays), the asset's weekday (excluding Demand Response Holiday) Demand Response Baseline in each five-minute interval shall be the simple average of meter data for the same five-minute interval from 10 weekdays (excluding Demand Response Holidays), chosen from the previous 30 weekdays (excluding Demand Response Holidays) as follows:~~

- ~~(a) If at least 10 of the previous 30 weekdays (excluding Demand Response Holidays) meet the following criteria, then the 10 most recent such days will be used: (i) the resource associated with the asset has not received a Dispatch Instruction for an amount greater than 0 MW; and (ii) if the asset is on a forced or scheduled curtailment, actual meter data values have not been submitted for any interval of the day pursuant to Section III.8B.6.3.~~
- ~~(b) If less than 10 of the previous 30 weekdays (excluding Demand Response Holidays) meet the criteria in (a), then, in addition to those days that meet the criteria in (a), the most recent weekday (excluding Demand Response Holidays) that does not meet one or more of the criteria in (a) will be used, until 10 days are identified.~~

~~**8B.4 — Determining the Meter Data Used to Calculate the Demand Response Baseline for a Saturday Day Type or a Sunday and Demand Response Holiday Day Type**~~

~~**8B.4.1 — Determining the Meter Data Used to Calculate the Demand Response Baseline for a Saturday Day Type**~~

~~For a Saturday day type: For a Demand Response Asset that has established an initial Demand Response Baseline for Saturdays, the asset's Demand Response Baseline in each five-minute interval shall be the simple average of meter data for the same five-minute interval from five Saturdays, chosen from the previous 42-calendar days as follows:~~

- ~~(a) If at least five Saturdays meet the following criteria, then the five most recent such days will be used: (i) the resource associated with the asset did not receive a Dispatch Instruction for an amount greater than 0 MW; and (ii) if the asset is on a forced or scheduled curtailment, actual meter data values were not submitted for any interval of the day pursuant to Section III.8B.6.3.~~
- ~~(b) If less than five Saturdays meet the criteria in (a), then, in addition to those days that meet the criteria in (a), the most recent Saturday that does not meet one or more of the criteria in (a) will be used, until five days are identified.~~

~~8B.4.2 — Determining the Meter Data Used to Calculate the Demand Response Baseline for a Sunday and Demand Response Holiday Day Type~~

~~For a Sunday and Demand Response Holiday day type: For a Demand Response Asset that has established an initial Demand Response Baseline for Sundays and Demand Response Holidays, the asset's Sunday and Demand Response Holiday Demand Response Baseline in each five-minute interval shall be the simple average of meter data for the same five-minute interval from five Sundays and Demand Response Holidays, chosen from the previous 42-calendar days as follows:~~

- ~~(a) If at least five Sundays and Demand Response Holidays meet the following criteria, then the five most recent such days will be used: (i) the resource associated with the asset did not receive a Dispatch Instruction for an amount greater than 0 MW; and (ii) if the asset is on a forced or scheduled curtailment, actual meter data values were not submitted for any interval of the day pursuant to Section III.8B.6.3.~~
- ~~(b) If less than five Sundays and Demand Response Holidays meet the criteria in (a), then, in addition to those days that meet the criteria in (a), the most recent Sunday or Demand Response Holiday that does not meet one or more of the criteria in (a) will be used, until five days are identified.~~

~~8B.5 — Baseline Adjustment~~

~~The Demand Response Baseline for each Demand Response 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 start of the quarter hour 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 start of the quarter hour 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.~~
- ~~(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 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 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 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 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, 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 for the day type, calculated on the first occurrence of that day type during the forced or scheduled curtailment, for all intervals excluding those intervals in which:~~

- ~~(a) a Capacity Scarcity Condition existed in the Capacity Zone in which the Demand Response Asset is located, or~~
- ~~(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.~~

~~III.8B.6.3—Performance Assessment for Days with Forced or Scheduled Curtailments~~

~~To assess the performance of Demand Response Assets that are on a forced or scheduled curtailment, actual meter data values shall be submitted to the ISO for intervals during which:~~

- ~~(a) a Capacity Scarcity Condition existed in the Capacity Zone in which the Demand Response Asset is located, or~~
- ~~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.~~

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 follow Dispatch Instructions during the Operating Day. The Resource must meet the technical requirements associated with the provision of ~~Forward-Operating~~ 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~~ Resource 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 Market Participant weekly and shall become effective at 0001 of the Monday following the distribution.

5. The values described in Sections III.9.5.3.1~~(-1)~~(a) and (b) shall not include any dispatch where:

a) The Resource is dispatched at the request of the Market Participant or Designated Entity and the dispatch was not related to an Establish Claimed Capability Audit request made pursuant to Section III.1.5.1.2, a Seasonal DR Audit request made pursuant to Section III.1.5.1.3.1, or a CLAIM10 or CLAIM30 audit request made pursuant to Section III.9.5.3.2;

b) The prices associated with the Blocks to Economic Min for the Real-Time dispatch of the Resource are less than or equal to zero; ~~or~~

c) For generating Resources, the ratio of (i) the sum of the applicable Start-up Fee, No-Load Fee for one hour, and energy cost to Economic Min used in the Real-Time dispatch of the Resource in the Operating Day to (ii) the maximum total hourly Start-up Fee, No-Load Fee for one hour, and energy cost to Economic Min submitted for the Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold value determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to (i) differences in cost between Gas Days, or (ii) a reduction in the cost of gas within the Operating Day reflected in the offers submitted for the Resource during the remainder of the Operating Day, then the Market Participant may request that the ISO evaluate whether the dispatch may be included; or

d) For Demand Response Resources, the ratio of (i) the sum of the applicable Interruption Cost and the demand reduction cost to Minimum Reduction used in the Real-Time dispatch of the Demand Response Resource in the Operating Day to (ii) the maximum total hourly Interruption Cost and demand reduction cost to Minimum Reduction submitted for the Demand Response Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to differences in cost between Gas Days, then the Market Participant may request that the ISO evaluate whether the dispatch may be included.

6. A Demand Response Resource's CLAIM10 and CLAIM30 values on June 1, 2018 and October 1, 2018 shall be as follows:

a) On June 1, 2018 and October 1, 2018, the CLAIM10 value of a Demand Response Resource shall equal zero.

b) On June 1, 2018, the CLAIM30 value of a Demand Response Resource with one or more Demand Response Assets that were associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource" (as those terms were defined prior to June 1, 2018) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Summer Capability Period beginning June 1, 2017. Such a CLAIM30 value shall remain valid until the earlier of: (i) July 2, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 value pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before June 27, 2018, its CLAIM30 value shall be set to zero on July 2, 2018.

c) On October 1, 2018, the CLAIM30 value of a Demand Response Resource with one or more Demand Response Assets that were associated with a “Real-Time Demand Response Resource” or a “Real-Time Emergency Generation Resource” (as those terms were defined prior to June 1, 2018) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Winter Capability Period beginning October 1, 2017. Such a CLAIM30 value shall remain valid until the earlier of: (i) October 29, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 value pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before October 24, 2018, its CLAIM30 value shall be set to zero on October 29, 2018.

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 not request more than one audit per week for the same Resource, provided that, if the Resource fails to start ~~or~~ trips offline, or becomes unavailable to provide a demand reduction during the audit, then the Market Participant may request another audit in the same week. The ISO, at its sole discretion, may allow a Market Participant to request more than one audit per week for the same Resource if the Resource historically has multiple startup dispatches included in its CLAIM10 or CLAIM30 calculations per week. 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 ~~b~~Business ~~d~~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 ~~b~~Business ~~d~~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:

$$\text{performance factor} = \frac{\sum_{n=1}^{10} (\frac{\text{resource output or demand reduction at 10 or 30 minutes}_n \text{ (MW)}}{\text{resource target value}_n \text{ (MW)}} * n)}{\sum_{n=1}^{10} n}$$

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~~ pursuant to [Section III.8.3](#), 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 ~~that are Generator Assets or Dispatchable Asset Related Demand~~ 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 calculated as follows:

- (a) For each of the five most recently completed Summer Capability Periods or Winter Capability Periods (as applicable to the Forward Reserve Procurement Period), for each on-peak hour, the ISO shall calculate an implied heat rate, expressed in Btu/kWh, by dividing the hour's Hub Price by the lower of the applicable natural gas or heating oil price index.
- (b) All resulting hourly implied heat rates above 45,000 Btu/kWh shall be excluded, and the remaining values shall be listed in order from high to low.
- (c) The Forward Reserve Heat Rate for the Forward Reserve Procurement Period shall be the lesser of: (i) the heat rate that occurs at the 97.5th percentile of the list described in subsection (b) above; or (ii) 21,999 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.

(a) Generating Resources and Dispatchable Asset Related Demand – 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 a generating Resource's 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:

$$\frac{StartUp}{EcoMax \times 1 \text{ hour}} + \frac{NoLoad}{EcoMax} + EnergyOffer_i \geq ForwardReserveThresholdPrice$$

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 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.

(b) Demand Response Resources – 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:

$$\frac{\text{Interruption Cost}}{\text{MaxRed}} + \text{Energy Offer } i \geq \text{Forward Reserve Threshold Price}$$

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 increased ~~multiplied by one plus the~~ average avoided peak distribution losses, limited as described below.

(i) ~~The ISO It will be assumed that all Demand Response Assets associated with a~~ Demand Response Resources ~~must~~ first reduce their net load from the electricity system before providing additional Net Supply.

(ii) _____ The portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be the lesser of: (1) Forward Reserve Delivered Megawatts and (2); ~~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 based on the net load of its constituent Demand Response Assets.~~

(iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with Net Supply will be capped at the remaining Net Supply ~~Limit~~ capability of the Demand Response Resource.

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-increased~~ by ~~one plus the~~ average avoided peak distribution losses.

The portion of the Target Activation Megawatts not associated with Net Supply ~~shall be calculated as the greater is the lesser~~ of: (i) the Target Activation Megawatts minus the amount of Net Supply that the Demand Response Resource produced during activation or (ii) zero,

~~• 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)

FRACP_{Zone} is defined as 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 to:

applicable monthly FRACP_{Zone} for TMNSR 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:

applicable monthly FRACP_{Zone} for TMOR 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 TMNSR proxy system clearing price, plus the TMOR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the TMOR proxy system clearing price 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.

For purposes of this Section III.10, unless otherwise expressly stated, the settlement interval is five minutes. If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.10.1 Provision of Operating Reserve in Real-Time

For each Market Participant for each settlement interval, 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

(a) Each Market Participant shall have for each settlement interval 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 Metered Quantity For Settlement and the estimated Resource output utilized to determine the amount of Real-Time Reserve Designation.

~~(a)~~(b) Each Market Participant shall have for each settlement interval 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 Metered Quantity For Settlement 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. [Demand Response Resource credits will be limited as described in Section III.9.6.5\(h\).](#)

(a) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMSR for an hour shall be equal to the sum of the Real-Time Reserve Credit for TMSR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMSR for an interval is calculated by multiplying the Market Participant's Resource specific Real-Time Reserve Designation for TMSR ([where any portion of Real-Time Reserve Designation MW provided by a Demand Response Resource, other than MWs associated with Net Supply, is increased by average avoided peak distribution losses](#)) for the interval by the Real-Time Reserve Clearing Price for TMSR for the interval. The Real-Time Reserve Credit for TMSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific hourly Real-Time Reserve Credits for TMSR in that Load Zone.

(b) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMNSR shall be equal to the sum of the Real-Time Reserve Credit for TMNSR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMNSR for an interval is calculated by multiplying the Market Participant's Resource specific Real-Time Reserve Designation for TMNSR ([where any portion of Real-Time Reserve Designation MW provided by a Demand Response Resource, other than MWs associated with Net Supply, is increased by average avoided peak distribution losses](#)) for the interval by the Real-Time Reserve Clearing Price for TMNSR for the interval. The Real-Time Reserve Credit for TMNSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific hourly Real-Time Reserve Credits for TMNSR in that Load Zone.

(c) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMOR shall be equal to the sum of the Real-Time Reserve Credit for TMOR ([where any portion of Real-Time Reserve Designation MW provided by a Demand Response Resource, other than MWs associated with Net Supply, is increased by average avoided peak distribution losses](#)) for the settlement intervals in that hour. The Real-Time Reserve Credit for TMOR for an interval is calculated by multiplying the Market Participant's Resource specific Real-Time Reserve Designation for TMOR for the interval by the Real-Time Reserve Clearing Price for TMOR for the interval. 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:

$$\text{Real-Time Reserve Charge}_{k,i} = [\text{Reserve Charge Allocation MW}_{k,i}] \times [\text{RT_CHRG_RT}_i]$$

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.

$\text{RT_CHRG_RT}_i = [\text{IRT_SUP_PMNT}] / \text{RT_P_WTD_LD_OB}] \times [\text{RT_P_RATIO}]$ for TMSR, TMNSR, or TMOR, as applicable.

$\text{RT_P_WTD_LD_OB} = \sum [\text{Reserve Charge Allocation MW}_{s,i}] \times [\text{P_RATIO}_i]$ for TMSR, TMNSR or TMOR, as applicable;

$[\text{RT_SUP_PMNT}]$ = 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_RATIO_i 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 settlement interval such that a Market Participant will not receive compensation for Real-Time Operating Reserve MWs provided to satisfy a Forward Reserve Obligation.

For purposes of the calculations in this Section III.10.4: (1) when a Market Participant assigns a Forward Reserve Resource in one Reserve Zone to meet a Forward Reserve Obligation in another Reserve Zone, any Forward Reserve Obligation Charge megawatts associated with that Resource are allocated to the Reserve Zone in which the Market Participant holds the Forward Reserve Obligation; and (2) if a Market Participant satisfies a Forward Reserve Obligation for TMOR with Forward Reserve Delivered MW of TMNSR, the Forward Reserve Obligation Charge megawatts are allocated to the Market Participant's Forward Reserve Obligation for TMOR.

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 provided by a Demand Response Resource, other than MWs associated with Net Supply, 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.

III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

Prior to each Forward Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction in accordance with this Section III.12.1.

The ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation (“LOLE”) of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period. The Installed Capacity Requirement shall be determined assuming all resources pursuant to Sections III.12.7 and III.12.9 will be deliverable to meet the forecasted demand determined pursuant to Section III.12.8.

If the Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Installed Capacity Requirement. The modeling assumptions used in determining the Installed Capacity Requirement are specified in Sections III.12.7, III.12.8 and III.12.9. For the purpose of this Section III.12, a “resource” shall include generating resources, demand resources, and import capacity resources eligible to receive capacity payments in the Forward Capacity Market.

III.12.1.1. System-Wide Marginal Reliability Impact Values.

Prior to each Forward Capacity Auction, the ISO shall determine the system-wide Marginal Reliability Impact of incremental capacity at various capacity levels for the New England Control Area. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used in determining the Installed Capacity Requirement.

III.12.2. Local Sourcing Requirements and Maximum Capacity Limits.

Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section

III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction. The Local Sourcing Requirement shall represent the minimum amount of capacity that must be procured within an import-constrained Capacity Zone. The Maximum Capacity Limit shall represent the maximum amount of capacity that can be procured in an export-constrained Capacity Zone to meet the Installed Capacity Requirement.

The ISO shall use consistent assumptions and standards to establish a resource's electrical location for purposes of qualifying a resource for the Forward Capacity Market and for purposes of calculating Local Sourcing Requirements and Maximum Capacity Limits. The methodology used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.2.1 and III.12.2.2, respectively. The modeling assumptions used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.5, III.12.6, III.12.7, III.12.8 and III.12.9.

III.12.2.1. Calculation of Local Sourcing Requirements for Import-Constrained Capacity Zones.

For each import-constrained Capacity Zone, the Local Sourcing Requirement shall be the amount needed to satisfy the higher of: (i) the Local Resource Adequacy Requirement as determined pursuant to Section III.12.2.1.1; or (ii) the Transmission Security Analysis Requirement as determined pursuant to Section III.12.2.1.2.

III.12.2.1.1. Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

(a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the import-constrained side of the interface, if any; and (ii) the rest of the New England Control Area which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits on the unconstrained side of the interface, if any.

(b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Local Resource Adequacy Requirement for the import-constrained Capacity Zone Z shall be determined in accordance with the following formula:

$$LRA_z = Resources_z + Proxy Units_z - (Proxy Units Adjustment_z(1-FOR_z)) - (Firm Load Adjustment_z(1-FOR_z))$$

In which:

- LRA_z = MW of Local Resource Adequacy Requirement for Capacity Zone Z;
- $Resources_z$ = MW of resources electrically located within Capacity Zone Z, including import Capacity Resources on the import-constrained side of the interface, if any;
- $Proxy Units_z$ = MW of proxy unit additions in Load Zone Z;
- $Firm Load Adjustment_z$ = MW of firm load added (or subtracted) within Capacity Zone Z to make the LOLE of the New England Control Area equal to 0.105 days per year; and
- FOR_z = Capacity weighted average of the forced outage rate modeled for all resources within Capacity Zone Z, including and proxy unit additions to Capacity Zone Z.

Proxy Units

Adjustment = MW of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1 days/year.

To determine the Local Resource Adequacy Requirement, the firm load is adjusted within Capacity Zone Z until the LOLE of the New England Control Area reaches 0.105 days per year. The LOLE of 0.105 days per year includes an allowance for transmission related LOLE of 0.005 days per year associated with each interface. As firm load is added to (or subtracted from) Capacity Zone Z, an equal amount of firm load is removed from (or added to) the rest of New England Control Area.

III.12.2.1.2. Transmission Security Analysis Requirement.

A Transmission Security Analysis shall be used to determine the requirement of the zone being studied, and shall include the following features:

- (a) The ISO shall perform a series of transmission load flow studies and/or a deterministic operable capacity analysis targeted at determining the performance of the system under stressed conditions, and at developing a resource requirement sufficient to allow the system to operate through those stressed conditions.
- (b) The Transmission Security Analysis Requirement shall be set at a level sufficient to cover most reasonably anticipated events, but will not guarantee that every combination of obligated resources within the zone will meet system needs.
- (c) In performing the Transmission Security Analysis, the ISO may establish static transmission interface transfer limits, as identified pursuant to Section III.12.5, as a reasonable representation of the transmission system's capability to serve load with available existing resources.
- (d) The Transmission Security Analysis may model the entire New England system and individual zones, for both the first contingency (N-1) and second contingency (N-1-1) conditions. First contingency conditions (N-1) shall include the loss of the most critical generator or most critical transmission element with respect to the zone. Second contingency conditions (N-1-1) shall include both: (i) the loss of the most critical generator with respect to the zone followed by the loss of the most critical transmission

element (“Line-Gen”); and (ii) the loss of the most critical transmission element followed by the loss of the next most critical transmission element (“Line-Line”) with respect to the zone.

III.12.2.1.3. Marginal Reliability Impact Values for Import-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each import-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) shall be reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero.

III.12.2.2. Calculation of Maximum Capacity Limit for Export-Constrained Capacity Zones.

For each export-constrained Capacity Zone, the Maximum Capacity Limit shall be calculated using the following method:

- (a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the export-constrained side of the interface, if any; and (ii) the rest of the New England Control Area, which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits to the rest of the New England Control Area, if any.
- (b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.
- (c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Maximum Capacity Limit for the export-constrained Capacity Zone Y shall be determined in accordance with the following formula:

$$\text{Maximum Capacity Limit}_Y = \text{ICR} - \text{LRA}_{\text{RestofNewEngland}}$$

In which:

Maximum Capacity Limit_Y = Maximum MW amount of resources, including Import Capacity Resources on the export-constrained side of the interface, if any, that can be procured in the export-constrained Capacity Zone Y to meet the Installed Capacity Requirement;

ICR = MW of Installed Capacity Requirement for the New England Control Area, determined in accordance with Section III.12.1; and

LRA_{RestofNewEngland} = MW of Local Sourcing Requirement for the rest of the New England Control Area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Section III.12.2.1.

III.12.2.2.1. Marginal Reliability Impact Values for Export-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each export-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit.

III.12.3 Consultation and Filing of Capacity Requirements.

At least two months prior to filing the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves with the Governance Participants, the state utility regulatory

agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act 90 days prior to the Forward Capacity Auction for the Capacity Commitment Period. The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given FCA, any new Capacity Zone must have received approval from the Commission prior to the Existing Capacity Qualification Deadline of the applicable FCA.

III.12.4. Capacity Zones.

For each Forward Capacity Auction, the ISO shall, using the results of the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K, determine the Capacity Zones to model as described below, and will include such designations in its filing with the Commission pursuant to Section III.13.8.1(c):

(a) The ISO shall model in the Forward Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit is less than the sum of the existing qualified capacity and proposed new capacity that could qualify to be procured in the export constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface.

(b) The ISO shall model in the Forward Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the second contingency transmission capability results in a line-line Transmission Security Analysis Requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, that is greater than the Existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model out-of-service all Retirement De-List Bids and Permanent De-List Bids (including any received for the current FCA at the time of this calculation) as well as rejected for

reliability Static De-List Bids from the most recent previous Forward Capacity Auction and rejected for reliability Dynamic De-List Bids from the most recent previous Forward Capacity Auction.

(c) Adjacent Load Zones that are neither export-constrained nor import-constrained shall be modeled together as the Rest of Pool Capacity Zone in the Forward Capacity Auction.

III.12.4A. 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 of Active Demand Capacity 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.12.5. Transmission Interface Limits.

Transmission interface limits, used in the determination of Local Sourcing Requirements, shall be determined pursuant to ISO Tariff Section II, Attachment K using network models that include all resources, existing transmission lines and proposed transmission lines that the ISO determines, in accordance with Section III.12.6, will be in service no later than the first day of the relevant Capacity Commitment Period. The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

III.12.6. Modeling Assumptions for Determining the Network Model.

The ISO shall determine, in accordance with this Section III.12.6, the generating units and transmission infrastructure to include in the network model that: (i) are expected to be in service no later than the first day of the relevant Capacity Commitment Period; and (ii) may have a material impact on the network model, a potential interface constraint, or on one or more Local Sourcing Requirements. The network model shall be used, among other purposes, (i) for the Forward Capacity Market qualification process and (ii) to calculate transmission interface limits in order to forecast the Local Sourcing Requirements. The network model shall include:

(a) For the relevant Capacity Commitment Period, the network model shall include:

(i) all existing resources, along with any associated interconnection facilities and/or Elective Transmission Upgrades that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Section III.13.2.5.2.5.3;

(ii) all new resources with Qualified Capacity for the relevant Capacity Commitment Period, along with any associated interconnection facilities and/or Elective Transmission Upgrades; and

iii. in the case of an initial interconnection analysis that is conducted consistent with the Network Capability Interconnection Standard, any generating unit or External Elective Transmission Upgrade that has a valid Interconnection Request and is reasonably expected to declare commercial operation no later than the first day of the relevant Capacity Commitment Period.

(b) Prior to each Forward Capacity Auction and each annual reconfiguration auction, the ISO shall determine and publish a list of the transmission projects and elements of transmission projects that will be included in the network model. During the process of making the transmission infrastructure determinations, as described in Section III.12.6.1, the ISO shall consult with the Governance Participants, the Transmission Owners, any transmission project proponents, the state utility regulatory agencies in New England and, as appropriate, other state agencies.

III.12.6.1. Process for Establishing the Network Model.

(a) The ISO shall establish an initial network model prior to the Forward Capacity Auction that only includes transmission infrastructure, including Internal Elective Transmission Upgrades, that is already in service at the time that the initial network model is developed.

(b) After establishing the initial network model, the ISO shall compile a preliminary list of the transmission projects or elements of transmission projects in the RSP Project List, individually or in combination with each other, as appropriate, to identify transmission projects that may achieve an in-service date no later than the first day of the relevant Capacity Commitment Period and that will have a material impact on the network model, on a potential interface constraint or one or more Local Sourcing Requirements.

(c) For the transmission projects or elements of transmission projects in the RSP Project List that are included in the preliminary list developed pursuant to subsection (b), the ISO shall determine whether the transmission projects or elements of transmission projects meet all of the initial threshold milestones specified in Section III.12.6.2 and will be considered for further evaluation pursuant to subsection (d).

(d) For those transmission projects or elements of transmission projects that meet the initial threshold milestones in subsection (c), the ISO shall use the evaluation criteria specified in Section III.12.6.3, and any other relevant information, to determine whether to include a transmission project or element of a transmission project in the final network model.

(e) If after completing its evaluation pursuant to Sections III.12.6.1 through III.12.6.3 and conferring with the transmission project proponents, the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO determines that the transmission project or a portion of the transmission project is reasonably expected to be in service no later than the first day for the relevant Capacity Commitment Period, then such transmission project or portion of transmission project shall be considered in service in the finalized network model to calculate the transmission interface limits pursuant to Section III.12.5.

III.12.6.2. Initial Threshold to be Considered In-Service.

The ISO shall determine whether transmission projects or elements of transmission projects meet all of the following initial threshold milestones:

(a) A critical path schedule for the transmission project has been furnished to ISO showing that the transmission project or the element of the transmission project will be in-service no later than the first day of the relevant Capacity Commitment Period. The critical path schedule must be sufficiently detailed to allow the ISO to evaluate the feasibility of the schedule.

(b) At the time of the milestone review, siting and permitting processes, if required, are on schedule as shown on the critical path schedule.

(c) At the time of the milestone review, engineering is on schedule as shown on the critical path schedule.

(d) At the time of the milestone review, land acquisition, if required, is on schedule as shown on the critical path schedule.

(e) Corporate intent to build the transmission project has been furnished to the ISO. An officer of the host Transmission Owner or Elective Transmission Upgrade Interconnection Customer has submitted to the ISO a statement verifying that the officer has reviewed the proposal and critical path schedule submitted to the ISO, and the Transmission Owner or Elective Transmission Upgrade Interconnection Customer concurs that the schedule is achievable, and it is the intent of the Transmission Owner or Elective Transmission Upgrade Interconnection Customer to build the proposed transmission project in accordance with that schedule. The Transmission Owner or Elective Transmission Upgrade Interconnection Customer may develop alternatives or modifications to the transmission project during the course of design of the transmission project that accomplish at least the same transfer capability. Such alternatives or modifications are acceptable, so long as the ISO determines that the alternative or modification is reasonably expected to achieve an in-service date no later than the first day of the relevant Capacity Commitment Period. The provision of an officer's statement shall be with the understanding that the statement shall not create any liability on the officer and that any liability with respect to the Transmission Owner's obligations shall be as set forth in the Transmission Operating Agreement and shall not be affected by such officer's statement.

III.12.6.3. Evaluation Criteria.

For a transmission project or element of a transmission project that meets the initial threshold milestones specified in Section III.12.6.2, the ISO shall consider the following factors and any other relevant information to determine whether to include the transmission project or element of the transmission project in the network model for the relevant Capacity Commitment Period.

(a) Sufficient engineering to initiate construction is on schedule as shown on the critical path schedule.

(b) Approval under Section I.3.9 of the Transmission, Markets and Services Tariff, if required, has been obtained or is on schedule to be obtained as shown on the critical path schedule.

(c) Significant permits, including local permits, if required to initiate construction have been obtained or are on schedule consistent with the critical path schedule.

(d) Easements, if required, have been obtained or are on schedule consistent with the critical path schedule. Needed land purchases, if required, have been made or are on schedule consistent with the critical path schedule.

(e) Any contracts required to procure or construct a transmission project are in place consistent with the critical path schedule. The ISO's analysis may also take into account whether such contracts contain incentive and/or penalty clauses to encourage third parties to advance the delivery of material services to conform with the critical path schedule.

(f) Physical site work is on schedule consistent with the critical path schedule.

(g) The transmission project is in a designated National Interest Electric Transmission Corridor in accordance with Section 216 of the Federal Power Act, 16 U.S.C. §§ 824p.

III.12.7. Resource Modeling Assumptions.

III.12.7.1. Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as additional capacity to determine the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all other resources in the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

When modeling transmission constraints for the determination of Local Resource Adequacy Requirements, the same proxy units may be added to the import-constrained zone or elsewhere in the rest of the New England Control Area depending on where system constraints exist.

III.12.7.2. Capacity.

The resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall include:

- (a) all Existing Generating Capacity Resources,
- (b) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,
- (c) all Existing Import Capacity Resources backed by a multiyear contract to provide capacity in the New England Control Area, where that multiyear contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and
- (d) Existing Demand Capacity Resources that are qualified to participate in the Forward Capacity Market and New Demand Capacity Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

but shall exclude:

- (e) capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,
- (f) capacity de-listed or retired as a result of Permanent De-List Bids or Retirement De-List Bids in previous Forward Capacity Auctions, and
- (g) capacity retired pursuant to Section III.13.1.2.4.1(a), unless the Lead Market Participant has opted to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1.

The rating of Existing Generating Capacity Resources and Existing Import Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be the summer Qualified Capacity value of such resources for the relevant zone. The rating of Demand Capacity Resources shall be the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value. The rating of resources, except for Demand Capacity Resources, cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period shall be

based on the amount of Qualified Capacity that cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period. Resources are located within the Capacity Zones in which they are electrically connected as determined during the qualification process.

III.12.7.2.1. [Reserved.]

III.12.7.3. Resource Availability.

The Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated taking resource availability into account and shall be determined as follows:

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The most recent five-year moving average of EFORd shall be used as the measure of resource availability for non-peaking resources used in the calculation of Transmission Security Analysis Requirements. A deterministic adjustment factor, based on the operational experience of the ISO, shall be used as the measure of resource availability for peaking resources used in the calculation of Transmission Security Analysis Requirements, and will be reviewed periodically.

(b) [Reserved.]

(c) Once sufficient data are collected under the availability incentives in the Forward Capacity Market, a resource availability metric, which reflects resource availability in a manner that is consistent with the availability incentives in the Forward Capacity Market, shall be developed and reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies and used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

For resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that do not have sufficient data to calculate an availability metric as defined in subsections (a) or (c) above, class average data for similar resource types shall be used. For Demand Capacity Resources, historical performance data for those resources will be used to develop an

availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

III.12.7.4. Load and Capacity Relief.

Load and capacity relief expected from system-wide implementation of the following actions specified in ISO New England Operating Procedure No. 4. Action During a Capacity Deficiency, shall be included in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values:

- (a) **Implement voltage reduction.** The MW value of the load relief shall be equal to the percentage load reduction achieved in the most applicable voltage reduction tests multiplied by the forecasted seasonal peak loads.
- (b) **Arrange for available Emergency energy from Market Participants or neighboring Control Areas.** These actions are included in the calculation through the use of tie benefits to meet system needs. The MW value of tie benefits is calculated in accordance with Section III.12.9.
- (c) **Maintain an adequate amount of ten-minute synchronized reserves.** The amount of system reserves included in the determination of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be consistent with those needed for reliable system operations during Emergency Conditions. When modeling transmission constraints, the reserve requirement for a zone shall be the zone's pro rata share of the forecasted system peak load multiplied by the system reserves needed for reliable system operations during Emergency Conditions.

III.12.8. Load Modeling Assumptions.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias.

Demand Capacity Resources shall be reflected in the load forecast as specified below:

(a) Expected reductions from an installed or forecast Demand Capacity Resource not qualifying for or not participating in the Forward Capacity Auction shall be reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period. The expected reduction from these resources will be included in the load forecast to the extent that they meet the qualification process rules, including monitoring and verification plan and financial assurance requirements. If no qualification process rules are in place for the expected reductions from these resources, they shall not be included within the load forecast.

(b) Expected reductions from an installed or forecast Demand Capacity Resource that qualifies to participate in the Forward Capacity Market, participates but does not clear in the Forward Capacity Auction, or has cleared in a previous Forward Capacity Auction and is expected to continue in the Forward Capacity Market shall not be reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period.

(c) [Reserved.]

(d) Any realized Demand Capacity Resource reductions in the historical period that received Forward Capacity Market payments for these reductions, or Demand Capacity Resource reductions that are expected to receive Forward Capacity Market payments by participating in the upcoming Forward Capacity Auction or having cleared in a previous Forward Capacity Auction, shall be added back into the appropriate historical loads to ensure that such resources are not reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period.

III.12.9. Tie Benefits.

The Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated assuming appropriate tie benefits, if any, available from interconnections with neighboring Control Areas. Tie benefits shall be calculated only for interconnections (1) without Capacity Network Import Interconnection Service or Network Import Interconnection Service or (2) that have not requested Capacity Network Import Interconnection Service

or Network Import Interconnection Service with directly interconnected neighboring Control Areas with which the ISO has in effect agreements providing for emergency support to New England, including but not limited to inter-Control Area coordination agreements, emergency aid agreements and the NPCC Regional Reliability Plan.

Tie benefits shall be calculated using a probabilistic multi-area reliability model, by comparing the LOLE for the New England system before and after interconnecting the system to the neighboring Control Areas. To quantify tie benefits, firm capacity equivalents shall be added until the LOLE of the isolated New England Control Area is equal to the LOLE of the interconnected New England Control Area.

III.12.9.1. Overview of Tie Benefits Calculation Procedure.

III.12.9.1.1. Tie Benefits Calculation for the Forward Capacity Auction and Annual Reconfiguration Auctions; Modeling Assumptions and Simulation Program.

For each Capacity Commitment Period, tie benefits shall be calculated for the Forward Capacity Auction and the third annual reconfiguration auction using the calculation methodology in this Section III.12.9.

For the first and second annual reconfiguration auctions for a Capacity Commitment Period, the tie benefits calculated for the associated Forward Capacity Auction shall be utilized in determining the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values as adjusted to account for any changes in import capability of interconnections with neighboring Control Areas and changes in import capacity resources using the methodologies in Section III.12.9.6.

Tie benefits shall be calculated using the modeling assumptions developed in accordance with Section III.12.9.2 and using the General Electric Multi-area Reliability Simulation (MARS) program.

III.12.9.1.2. Tie Benefits Calculation.

The total tie benefits to New England from all directly interconnected neighboring Control Areas are calculated first using the methodology in Section III.12.9.3. Following the calculation of total tie benefits, individual tie benefits from each qualifying neighboring Control Area are calculated using the methodology in Section III.12.9.4.1. If the sum of the tie benefits from each Control Area does not equal the total tie benefits to New England, then each Control Area's tie benefits are adjusted based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits calculated for each Control Area using the methodology in Section III.12.9.4.2. Following this calculation, tie benefits are calculated for

each qualifying individual interconnection or group of interconnections using the methodology in Section III.12.9.5.1. If the sum of the tie benefits from individual interconnections or groups of interconnections does not equal their associated Control Area's tie benefits, then the tie benefits of each individual interconnection or group of interconnections is adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits within the Control Area using the methodology in Section III.12.9.5.2.

III.12.9.1.3. Adjustments to Account for Transmission Import Capability and Capacity Imports.

Once the initial calculation of tie benefits is performed, the tie benefits for each individual interconnection or group of interconnections is adjusted to account for capacity imports and any changes in the import capability of interconnections with neighboring Control Areas, using the methodologies in Section III.12.9.6. Once the import capability and capacity import adjustments are completed, the sum of the tie benefits of all individual interconnections and groups of interconnections for a Control Area, with the import capability and capacity import adjustments, represents the tie benefits associated with that Control Area, and the sum of the tie benefits from all Control Areas, with the import capability and capacity import adjustments, represents the total tie benefits available to New England.

III.12.9.2. Modeling Assumptions and Procedures for the Tie Benefits Calculation.

III.12.9.2.1. Assumptions Regarding System Conditions.

In calculating tie benefits, "at criterion" system conditions shall be used to model the New England Control Area and all interconnected Control Areas.

III.12.9.2.2. Modeling Internal Transmission Constraints in New England.

In calculating tie benefits, all New England internal transmission constraints that (i) are modeled in the most recent Regional System Plan resource adequacy studies and assessments and (ii) are not addressed by either a Local Sourcing Requirement or a Maximum Capacity Limit calculation shall be modeled, using the procedures in Section III.12.9.2.5.

III.12.9.2.3. Modeling Transmission Constraints in Neighboring Control Areas.

The ISO will review annually NPCC's assumptions regarding transmission constraints in all directly interconnected neighboring Control Areas that are modeled for the tie benefits calculations. In the event that NPCC models a transmission constraint in one of the modeled neighboring Control Areas, the ISO

will perform an evaluation to determine which interfaces are most critical to the ability of the neighboring Control Area to reliably provide tie benefits to New England from both operational and planning perspectives, and will model those transmission constraints in the tie benefits calculation, using the procedures in Section III.12.9.2.5.

III.12.9.2.4. Other Modeling Assumptions.

A. External transfer capability determinations. The transfer capability of all external interconnections with New England will be determined using studies that take account of the load, resource and other electrical system conditions that are consistent with those expected during the Capacity Commitment Period for which the calculation is being performed. Transfer capability studies will be performed using simulations that consider the contingencies enumerated in sub-section (iii) below.

- (i) The transmission system will be modeled using the following conditions:
 1. The forecast 90/10 peak load conditions for the Capacity Commitment Period;
 2. Qualified Existing Generating Capacity Resources reflecting their output at their Capacity Network Resource level;
 3. Qualified Existing Demand Capacity Resources reflecting their Capacity Supply Obligation received in the most recent Forward Capacity Auction;
 4. Transfers on the transmission system that impact the transfer capability of the interconnection under study.
- (ii) The system will be modeled in a manner that reflects the design of the interconnection. If an interconnection and its supporting system upgrades were designed to provide incremental capacity into the New England Control Area, simulations will assume imports up to the level that the interconnection was designed to support. If the interconnection was not designed to be so comparably integrated, simulations will determine the amount of power that can be delivered into New England over the interconnection.
- (iii) The simulations will take into account contingencies that address a fault on a generator or transmission facility, loss of an element without a fault, and circuit breaker failure following the loss of an element or an association with the operation of a special protection system.

- B. In calculating tie benefits, New England capacity exports are removed from the internal capacity resources and are modeled as a resource in the receiving Control Area. The transfer capability of external interconnections is not adjusted to account for capacity exports.

III.12.9.2.5. Procedures for Adding or Removing Capacity from Control Areas to Meet the 0.1 Days Per Year LOLE Standard.

In calculating tie benefits, capacity shall be added or removed from the interconnected system of New England and its neighboring Control Areas, until the LOLE of New England and the LOLE of each Control Area of the interconnected system equals 0.1 days per year simultaneously. The following procedures shall be used to add or remove capacity within New England and the interconnected Control Areas to achieve that goal.

- A. **Adding Proxy Units within New England when the New England system is short of capacity.** In modeling New England as part of the interconnected system, if New England is short of capacity to meet the 0.1 days per year LOLE, proxy units (with the characteristics identified in Section III.12.7.1) will be added to the sub-areas that are created by any modeled internal transmission constraints within New England, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the New England Control Area, then proxy units will be added to the entire Control Area. If, as a result of the addition of one or more proxy units, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(b) will be used to remove the surplus capacity.
- B. **Removing capacity from New England when the New England system is surplus of capacity.** In modeling New England as part of the interconnected system, if New England is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in these surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the Existing Qualified Capacity, and any amount of proxy units added in that sub-area that is above its 50-50 peak load forecast. Notwithstanding the foregoing, if removing resources will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratios described above for the removal of capacity surplus. If there are no modeled internal transmission constraints in the New England Control Area, then the surplus capacity shall be removed from the entire Control Area.

- C. Adding capacity within neighboring Control Areas when the neighboring Control Area is short of capacity.** In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is short of capacity to meet the 0.1 days per year LOLE, additional capacity will be added to the neighboring Control Area's sub-areas that are created by any modeled internal transmission constraints, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the Control Area, then capacity will be added to the entire Control Area. The process that the neighboring Control Area utilizes in its resource adequacy study to meet its resource adequacy criterion will be utilized to add capacity to that Control Area. In filing the Installed Capacity Requirement values pursuant to Section III.12.3, the ISO will provide citations to any resource adequacy studies relied upon for these purposes. If, as a result of the capacity addition, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(d) shall be used to remove the surplus capacity.
- D. Removing capacity from neighboring Control Areas when the neighboring Control Area is surplus of capacity.** In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the neighboring Control Area's sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in the surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the installed capacity in the sub-area above its 50/50 peak load forecast. For a sub-area that has a minimum locational resource requirement above its 50/50 peak load forecast, the amount of capacity surplus is the amount of the installed capacity in the sub-area above its minimum locational resource requirement. Notwithstanding the foregoing, if removing resources from a sub-area will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratio of capacity surplus in the sub-area to the total capacity surplus in the those remaining surplus sub-areas. If there are no modeled internal transmission constraints in the neighboring Control Area, then the surplus capacity will be removed from the entire Control Area.
- E. Maintaining the neighboring Control Area's locational resource requirements.** In modeling a neighboring Control Area with internal transmission constraints, all minimum locational resource requirements in the Control Area's sub-areas as established by the neighboring Control Area's installed capacity requirement calculations shall be observed.

III.12.9.3. Calculating Total Tie Benefits.

The total tie benefits with all qualifying directly interconnected neighboring Control Areas shall be calculated by comparing the interconnection state of the New England system with all interconnections to neighboring Control Areas connected with the interconnection state of the New England system with all interconnections with neighboring Control Areas disconnected. To calculate total tie benefits:

- A. The New England system shall be interconnected with all directly interconnected neighboring Control Areas and the New England Control Area, and each neighboring Control Area shall be brought to 0.1 days per year LOLE simultaneously by adjusting the capacity of each Control Area, utilizing the methods for adding or removing capacity in Section III.12.9.2.5.
- B. Once the interconnected system is brought to 0.1 days per year LOLE, the LOLE of the New England Control Area shall be calculated a second time, with the New England system isolated from the rest of the interconnected system that was brought to 0.1 days per year LOLE.
- C. Total tie benefits shall be the sum of the amounts of firm capacity that needs to be added to the isolated New England Control Area at the point at which each interconnection with neighboring Control Areas interconnects in New England to bring the New England LOLE back to 0.1 days per year. This value is subject to adjustment in accordance with Section III.12.9.6.

III.12.9.4. Calculating Each Control Area's Tie Benefits.

III.12.9.4.1. Initial Calculation of a Control Area's Tie Benefits.

Tie benefits from each neighboring Control Area shall be determined by calculating the tie benefits for every possible interconnection state that has an impact on the tie benefit value between the New England system and the target neighboring Control Area. If two or more interconnections between New England and the target neighboring Control Area exist, then all interconnections grouped together will be used to represent the state of interconnection between New England and the target neighboring Control Area. The tie benefits from the target neighboring Control Area shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.4.2.

III.12.9.4.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual Control Area tie benefits calculated in accordance with Section III.12.9.4.1 is different than the total tie benefits from all Control Areas calculated in accordance with Section III.12.9.3, then each Control Area's tie benefits shall be increased or decreased based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits for each individual Control Area, so that the sum of each Control Area's tie benefits, after the pro-ration, is equal to the total tie benefits calculated in accordance with Section III.12.9.3. The pro-rated Control Area tie benefits are subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.5. Calculating Tie Benefits for Individual Ties.

Tie benefits shall be calculated for an individual interconnection or group of interconnections to the extent that a discrete and material transfer capability can be identified for the interconnection or group of interconnections. All interconnections or groups of interconnections shall have equal rights in calculating individual tie benefits, with no grandfathering or incremental tie capability treatment.

For purposes of calculating tie benefits, a group of interconnections refers to two or more AC lines that operate in parallel to form a transmission interface in which there are significant overlapping contributions of each line toward establishing the transfer limit, such that the individual lines in a group of interconnections cannot be assigned individual contributions.

III.12.9.5.1. Initial Calculation of Tie Benefits for an Individual Interconnection or Group of Interconnections.

Tie benefits for an individual interconnection or group of interconnections shall be calculated by calculating tie benefits for each possible interconnection state between the New England system and the individual interconnection or group of interconnections. The tie benefits from that interconnection or group of interconnections shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.5.2.

III.12.9.5.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual interconnection's or group of interconnection's tie benefits calculated in accordance with Section III.12.9.5.1 is different than the associated Control Area's tie benefits calculated in accordance with Section III.12.9.4, then the tie benefits of the individual interconnection or group of interconnections shall be adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits for each interconnection or group of interconnections in that Control Area, so that the sum of the tie benefits for each interconnection or group

of interconnections in the Control Area, after the pro-ration, is equal to the total tie benefits for the Control Area calculated in accordance with Section III.12.9.4. The pro-rated tie benefits for each interconnection or group of interconnections is subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.6. Accounting for Capacity Imports and Changes in External Transmission Facility Import Capability.

III.12.9.6.1. Accounting for Capacity Imports.

In the initial tie benefits calculations, capacity imports are modeled as internal resources in New England, and the import capability of the interconnections with neighboring Control Areas is not reduced to reflect the impact of capacity imports. After the initial tie benefits calculations, total tie benefits, tie benefits for each Control Area, and tie benefits from each individual interconnection or group of interconnections shall be adjusted to account for capacity imports using the methodology contained in this Section III.12.9.6.1. For the Forward Capacity Auction and third annual reconfiguration auction, this adjustment shall be applied to the tie benefit values calculated in accordance with Sections III.12.9.3, III.12.9.4 and III.12.9.5 respectively. For the first and second annual reconfiguration auctions, this adjustment shall be applied to the tie benefits values calculated for the Forward Capacity Auction.

- A.** Capacity imports shall be deducted from the import capability of each individual interconnection or group of interconnections to determine the available import capability of the interconnection or group of interconnections prior to accounting for tie benefits from those interconnections. The transfer capability of an interconnection or group of interconnections shall be determined using the procedures in Section III.12.9.2.4.A.
- B.** If the tie benefits value of an individual interconnection or group of interconnections, as determined in accordance with Section III.12.9.5, is greater than the remaining transmission import capability of the interconnection or group of interconnections after accounting for capacity imports, the tie benefit value of the individual interconnection or group of interconnections shall be equal to the remaining transmission import capability (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2). If the tie benefits value of an individual interconnection or group of interconnections is not greater than the remaining transmission import capability after accounting for capacity imports, then the tie benefit value of the individual interconnection or group of interconnections shall be equal to the value determined in accordance with Section

III.12.9.5 (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2).

- C. The tie benefits for each Control Area shall be the sum of the tie benefits from the individual interconnections or groups of interconnections with that Control Area, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.
- D. The total tie benefits from all qualifying neighboring Control Areas shall be the sum of the Control Area tie benefits, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.
- E. For purposes of determining the adjustment to tie benefits to account for capacity imports under this Section III.12.9.6.1, the capacity imports applicable for determining tie benefits for the Forward Capacity Auction shall be the Qualified Existing Import Capacity Resources for the relevant Capacity Commitment Period, and the capacity imports applicable for determining tie benefits for the annual reconfiguration auctions are those Import Capacity Resources that hold Capacity Supply Obligations for the relevant Capacity Commitment Period as of the time the tie benefits calculation is being performed for the annual reconfiguration auction.

III.12.9.6.2. Changes in the Import Capability of Interconnections with Neighboring Control Areas.

For purposes of calculating tie benefits for the Forward Capacity Auction and third annual reconfiguration auction, the most recent import capability values for an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the modeling of system conditions for the tie benefits calculation. In addition, for the first and second annual reconfiguration auctions, any changes to the import capability of an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the adjustment to tie benefits to account for capacity imports under Section III.12.9.6.1.

III.12.9.7. Tie Benefits Over the HQ Phase I/II HVDC-TF.

The tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1 shall be allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.

III.12.10. Calculating the Maximum Amount of Import Capacity Resources that May be Cleared Over External Interfaces in the Forward Capacity Auction and Reconfiguration Auctions.

For external interfaces, Import Capacity Resources shall be allowed in the Forward Capacity Auction and reconfiguration auctions up to the interface limit minus the tie benefits, calculated pursuant to Section III.12.9.1 or 12.9.2 over the applicable interface.

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 Capacity Resource or Existing Demand Capacity 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 Capacity Resource, New Generating Capacity Resource, New Import Capacity Resource, and New Demand Capacity 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 FCM Deposit.

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 Capacity Resource or Existing Demand Capacity 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.13.1.1.2. 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.13.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.2 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.13.1.1.3 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.13.1.1.3.A. Treatment of New Incremental Capacity and Existing Generating Capacity at the Same Generating Resource.

For incremental summer capacity seeking to participate in the Forward Capacity Auction pursuant to Section III.13.1.1.3 or incremental winter capacity that meets the investment thresholds in Section III.13.1.1.3 as applied to the resource's winter Qualified Capacity, if the incremental summer or winter capacity does not span the entire Capacity Commitment Period, then the ISO shall match the incremental summer or winter capacity with excess existing winter or summer Qualified Capacity at that same resource, as appropriate, not to exceed the Qualified Capacity of the existing portion of the resource, in order to cover the entire Capacity Commitment Period. This provision shall not apply to Intermittent Power Resources or Intermittent Settlement Only Resources.

III.13.1.1.4. 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 15 Business Days before the Existing Capacity Retirement 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 or an On-Peak Demand Resource (including every ~~Asset~~ that is part of the On-Peak Demand 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 or New Demand 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, or in the case of an Import Capacity Resource seeking to qualify with an Elective Transmission Upgrade be associated with, an Interconnection Request under Schedules 22, 23 or 25 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 interconnection procedures described in Schedules 22, 23 and 25 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 FCM 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. 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, 23 and 25 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 Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of

Schedule 23, or Section 4.4 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein or the New Capacity Show of Interest Form 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, 23 and 25 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 interconnection procedures described in Schedules 22, 23 and 25 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, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff. In the case of a resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource that is supported by an Internal Elective Transmission Upgrade, all Queue Positions associated with the project must be submitted in the New Capacity Show of Interest Form. 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 pursuant to Section III.13.1.1.2.2.1.

(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 achieve, prior to the close of the New Capacity Show of Interest Submission Window, control of the project site for the duration of the relevant Capacity Commitment Period, which shall be as defined in Section 4.1 of

Schedule 22, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

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. For an Import Capacity Resource associated with an Elective Transmission Upgrade that has not yet achieved Commercial Operation as

defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, major components shall also include, to the extent applicable, transmission facilities and associated substation equipment.

(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 of Section II of the Transmission, Markets and Services Tariff.

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. For incremental capacity qualified pursuant to Section III.13.1.1.3.A, this election shall apply to both the incremental amount of capacity and the existing Qualified Capacity matched to the incremental capacity at the same generating resource. 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 Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23 and Section 4.4 of Schedule 25 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 or Capacity Network Import Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22, 23 and 25 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) or Elective Transmission Upgrade Interconnection Customer 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) or Elective Transmission Upgrade Interconnection Customer, 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, 23 and 25 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 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, Section 1.7.1.3 of Schedule 23, or Section 3.2.1.3 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff 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(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 Resource; (ii) for the notification to a Conditional Qualified New 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 Resource, the Queue Position of the Conditional Qualified New 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 or New Demand ~~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 or Section III.13.1.4.~~1.1.62.5.3~~. Only the portion of the FCA Qualified Capacity of the resource that meets the requirements of Section III.13.1.1.7 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.

The submission of a Renewable Technology Resource election that satisfies the requirements of Section III.13.1.1.7 will invalidate a prior multi-year Capacity Supply Obligation and Capacity Clearing Price election for the same resource made pursuant to Section III.13.1.4.~~1.1.2.72.2.5~~ or Section III.13.1.1.2.2.4 for a Forward Capacity Auction.

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 Capacity Resource or Existing Demand Capacity 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.

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.13.1.2.2.1(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 there was a system-wide Capacity Scarcity Condition and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions 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(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 there was a system-wide Capacity Scarcity Condition and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions 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 Retirement 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 Retirement 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.13.1.1.3(a) but not the requirements of Section III.13.1.1.3(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.13.1.1.3(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.13.1.1.3. Such an election must be made in writing and must be received by the ISO no later than the close of the New Capacity Show of Interest Submission Window. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction meets the requirements of this Section, but the incremental amount of capacity does not span the entire Capacity Commitment Period, then the ISO shall match the incremental amount of capacity with excess Qualified Capacity at that same resource, not to exceed the Qualified Capacity of the existing portion of the resource, in order to cover the entire Capacity Commitment Period. This provision shall not apply to Intermittent Power Resources or Intermittent Settlement Only Resources.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Capacity Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Capacity 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 20 Business Days before the Existing Capacity Retirement 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 10 Business Days before the Existing Capacity Retirement Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, a Permanent De-List Bid, or a Retirement 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 Retirement Package and Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant to 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 15 Business Days before the Existing Capacity Retirement Deadline, as described in Section

III.13.1.1.1.6(b). All Permanent De-List Bids and Retirement De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline. All Static De-List Bids, Export Bids and Administrative Export 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. Permanent De-List Bids and Retirement De-List Bids may not be modified or withdrawn after the Existing Capacity Retirement Deadline, except as provided for in Section III.13.1.2.4.1. All Static 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, except as provided for in Section III.13.1.2.3.1.1. An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Permanent De-List Bid, or Retirement De-List Bid for an amount of capacity greater than its summer Qualified Capacity, unless the submittal is for the entire resource. Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.~~2.2.5~~1.1.2.7 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; neither a Permanent De-List Bid nor a Retirement De-List Bid may be combined with any other type of de-list or export bid.

Static De-List Bids and Export 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 for a Forward Capacity Auction is \$5.50/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.

III.13.1.2.3.1.1. Static De-List Bids.

A Lead Market Participant with an Existing Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation for that resource, or a portion thereof, 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 qualification process. 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). 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 Lead Market Participant must notify the ISO if the Existing Capacity Resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests).

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b), a Lead Market Participant that submitted a Static De-List Bid may: (a) lower the price of any price-quantity pair of a Static De-List Bid, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or; (b) withdraw any price-quantity pair of a Static De-List Bid.

III.13.1.2.3.1.2. [Reserved.]

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 qualification process. 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 at or 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 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 qualification process. 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 shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Permanent De-List Bids and Retirement De-List Bids.

(a) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would not accept a Capacity Supply Obligation permanently for all or part of a Generating Capacity Resource beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction qualification process.

(b) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would retire all or part of a Generating Capacity Resource from all New England Markets beginning at the start of a particular Capacity Commitment Period may submit a Retirement De-List Bid in the associated Forward Capacity Auction qualification process.

(c) No Permanent De-List Bid or Retirement De-List Bid may result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit unless the Permanent De-List Bid or Retirement De-List Bid is for the entire resource. Each Permanent De-List Bid and Retirement De-List Bid must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Permanent De-List Bids and Retirement De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2.1 and must include the additional documentation described in that section. Once submitted, no Permanent De-List Bid or Retirement De-List Bid may be withdrawn, except as provided in Section III.13.1.2.4.1.

III.13.1.2.3.1.5.1. Reliability Review of Permanent De-List Bids and Retirement De-List Bids During the Qualification Process.

During the qualification process, the ISO will review the following de-list bids to determine if the resource is needed for reliability: (1) Internal Market Monitor-accepted Permanent De-List Bids and Internal Market Monitor- accepted Retirement De-List Bids that are at or above the Forward Capacity Auction Starting Price; and (2) Permanent De-List Bids and Retirement De-List Bids for which the Lead Market Participant has opted to have the resource reviewed for reliability as described in Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) . The reliability review will be conducted according to Section III.13.2.5.2.5, except as follows:

- (a) Permanent De-List Bids and Retirement De-List Bids that cannot be priced (for example, due to the expiration of an operating license) will be reviewed first.
- (b) System needs associated with Permanent De-List Bids and Retirement De-List Bids for resources found needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1 will be reviewed with the Reliability Committee no later than 30 days after the ISO submits to the Commission the retirement filing described in Section III.13.8.1(a). The Lead Market Participant shall be notified as soon as practicable following the ISO's consultation with the Reliability Committee that the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons.
- (c) If the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1, the de-list bid shall be rejected and the resource shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(c) and compensated according to Section III.13.2.5.2.5, unless the resource declines to be retained for reliability, as provided in Section III.13.1.2.3.1.5.1(d).
- (d) No later than 10 Business Days after being informed that a resource is needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1, a Lead Market Participant may notify the ISO that it declines to provide the associated capacity for reliability. Such an election will be binding. A resource for which a Lead Market Participant has made such an election will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2.
- (e) Where a resource is determined not to be needed for reliability or where a Lead Market Participant notifies the ISO that it declines to provide capacity for reliability pursuant to Section

III.13.1.2.3.1.5.1(d), the capacity associated with the Permanent De-List Bid or Retirement De-List Bid will be treated as follows:

- (i) For a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected to retire the resource pursuant to Section III.13.1.2.4.1(a), the portion of the resource subject to the de-list bid will be retired as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(a).
- (ii) For a Permanent De-List Bid at or above the Forward Capacity Auction Starting Price, the portion of the resource subject to the de-list bid will be permanently de-listed coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(b).
- (iii) For a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the de-list bid will be continue to receive conditional treatment as described in Section III.13.1.2.4.1(b), Section III.13.2.3.2(b)(ii), and Section III.13.2.5.2.1.

III.13.1.2.3.1.6. Static De-List Bids, Permanent De-List Bids and Retirement 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, Permanent De-List Bids, or Retirement 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, Permanent De-List Bids, or Retirement 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 of Stations having Common Costs.

The Internal Market Monitor will review each Static De-List Bid, Permanent De-List Bid and Retirement De-List Bids 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 establish an Internal Market Monitor-determined or Internal Market Monitor-accepted price for the bid as described in Section III.13.1.2.3.2.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Capacity Resources.

The Internal Market Monitor shall review bids for Existing Capacity Resources as follows.

III.13.1.2.3.2.1. Static De-List Bids and Export Bids, Permanent De-List Bids, and Retirement De-List Bids at or Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid and each Export Bid at or above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the Existing Capacity Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2.A); (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).

The Internal Market Monitor shall review each Permanent De-List Bid greater than 20 MW that is above the Dynamic De-List Bid Threshold and each Retirement De-List Bid greater than 20 MW that is above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the net present value of the resource's expected cash flows (as determined pursuant to Section III.13.1.2.3.2.1.2.B); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); and (3) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). If more than one Permanent De-List Bid or Retirement De-List Bid is submitted by a single Lead Market Participant or its Affiliates (as used in Section III.A.24), the Internal Market Monitor shall review each such bid above the Dynamic De-List Bid Threshold if the sum of all such bids above the Dynamic De-List Bid Threshold is greater than 20 MW. The Internal Market Monitor shall review each Permanent De-List Bid and each Retirement De-List Bid submitted at any price pursuant to Section III.13.2.5.2.1(b) if the sum of the Permanent De-List Bids and Retirement De-List Bids submitted by the Lead Market Participant or its Affiliates (as used in Section III.A.24) is greater than 20 MW. Permanent De-List Bids and Retirement De-List Bids that are not reviewed by the Internal

Market Monitor shall be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

Sufficient documentation and information about each bid component must be included in the Existing Capacity Retirement Package or the Existing Capacity Qualification Package to allow the Internal Market Monitor to make the requisite determinations. If a Permanent De-List Bid or Retirement De-List Bid is submitted pursuant to Section III.13.2.5.2.1(b), all relevant updates to previously submitted documentation and information must be provided to support the newly submitted price and allow the Internal Market Monitor to make updated determinations. The updated information may include a request to discontinue the Permanent De-List Bid or Retirement De-List Bid such that it will not be entered into the Forward Capacity Auction, in which case the update must include sufficient supporting information on the nature of resource investments that were undertaken, or other materially changed circumstances, to allow the Internal Market Monitor to determine whether discontinuation is appropriate.

The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of its content, including 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, cash flows, opportunity costs, 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 Static De-List Bids and Export Bids.

If the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that a Static De-List Bid or an Export Bid is not consistent with the sum of the resource's net going forward costs plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable risk premium assumptions plus reasonable opportunity costs, then the Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid that is consistent with its determination of the foregoing. If an Internal Market Monitor-determined price is established for a Static De-List Bid or an Export Bid, 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(c) shall include an explanation of the Internal Market Monitor-determined price 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.

III.13.1.2.3.2.1.1.2. Review of Permanent De-List Bids and Retirement De-List Bids.

The Internal Market Monitor shall review those Permanent De-List Bids and Retirement De-List Bids identified in Section III.13.1.2.3.2.1 and, after due consideration and consultation with the Lead Market Participant, as appropriate, shall develop an Internal Market Monitor-accepted Permanent De-List Bid or an Internal Market Monitor-accepted Retirement De-List Bid. The Internal Market Monitor-accepted Permanent De-List Bid and Internal Market Monitor-accepted Retirement De-List Bid shall be equal to the Permanent De-List Bid or Retirement De-List Bid submitted by the Lead Market Participant unless the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s) for the same de-list bid. If the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s), the Internal Market Monitor shall calculate an Internal Market Monitor-accepted Permanent De-List Bid or Internal Market-Monitor-accepted Retirement De-List Bid that is consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The retirement determination notification described in Section III.13.1.2.4(a) and the filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the Internal Market

Monitor-accepted price and the Internal Market Monitor determination on any request to discontinue the Permanent De-List Bid or Retirement De-List Bid.

III.13.1.2.3.2.1.2.A. Static De-List Bid and Export Bid Net Going Forward Costs.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an Export Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net going forward costs in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. A Static De-List Bid or Export Bid at or above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing 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 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 that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period. 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.

$CQ_{\text{summer}}kW$ = 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 that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, 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 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. $\text{infIndex} = (1 + i)^4$

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.13.1.2.3.2.1.2.B Permanent De-List Bid and Retirement De-List Bid Net Present Value of Expected Cash Flows.

The Lead Market Participant for an Existing Capacity Resource that submits a Permanent De-List Bid or Retirement De-List Bid that is to be reviewed by the Internal Market Monitor shall report all expected costs, revenues, prices, discount rates and capital expenditures in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. The Internal Market Monitor will review the Lead Market Participant's submitted data to ensure that it is consistent with overall market conditions and reflects expected values.

The Internal Market Monitor will adjust any data that are inconsistent with overall market conditions or do not reflect expected values. The Internal Market Monitor shall enter all relevant expected costs, revenues, prices, discount rates and capital expenditures into a capital budgeting model and shall determine the net present value of the Existing Capacity Resource's expected cash flows as follows:

The net present value of the Existing Capacity Resource's expected cash flows is equal to (i) the net present value of the Existing Capacity Resource's net annual expected cash flows over the resource's remaining economic life (as determined pursuant to Section III.13.1.2.3.2.1.2.C) plus the net present value of the resource's expected terminal value, using the resource's discount rate, divided by (ii) the product of the resource's Qualified Capacity (in kilowatts) and 12 months.

The Existing Capacity Resource's net annual expected cash flow for the first Capacity Commitment Period of the resource's remaining economic life is the resource's expected annual net operating profit excluding expected capacity revenues less its expected capital expenditures in the Capacity Commitment Period.

The Existing Capacity Resource's net annual expected cash flow for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life is the resource's expected annual net operating profit less its expected capital expenditures in the Capacity Commitment Period.

Where:

Expected net operating profit, in dollars, is the Lead Market Participant's expected annual profit that might otherwise be avoided or not accrued if the resource were not subject to the obligations of a listed

capacity resource during the Capacity Commitment Period. Expected labor, maintenance, taxes, insurance, administrative and other normal expenses that can be avoided or not incurred if the resource is retired or permanently de-listed may be included. Service of debt is not an avoidable cost and may not be included.

Expected capacity revenues, in dollars, are the forecasted annual expected capacity revenues based on the Lead Market Participant's forecasted expected capacity prices for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life. The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the forecasted expected capacity prices. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions about expected resource additions, resource retirements, estimated Installed Capacity Requirements, estimated Local Sourcing Requirements, expected market conditions, and any other assumptions used to develop the forecasted expected capacity price in each Capacity Commitment Period.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the forecasted expected capacity prices, the Internal Market Monitor will replace the Lead Market Participant's forecasted expected capacity prices with the Internal Market Monitor's estimate thereof in each of the subsequent Capacity Commitment Periods of the resource's remaining economic life.

Expected capital expenditures, in dollars, are the Lead Market Participant's expected capital investments 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 Periods.

Expected terminal value, in dollars, for resources with five years or less of remaining economic life, is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource. For resources with more than five years of remaining economic life, the expected terminal value in the fifth year of the evaluation period is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource at the end of the resource's economic life plus the net present value of the Existing Capacity Resource's net annual expected cash flows from the sixth year of the evaluation period through the end of the resource's remaining economic life, using the resource's discount rate.

Discount rate is a value reflecting the Lead Market Participant's weighted average cost of capital for the Existing Capacity Resource adjusted to reflect the risk to cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B.

The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.

The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions associated with the cost of capital, risks and any other assumptions used to develop the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the weighted average cost of capital for the Existing Capacity Resource adjusted for risk, the Lead Market Participant has included risks not associated with cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B or the Lead Market Participant has submitted costs, revenues, capital expenditures or prices that are not reflective of expected values, the Internal Market Monitor will replace the Lead Market Participant's discount rate with a value determined by the Internal Market Monitor.

III.13.1.2.3.2.1.2.C Permanent De-List Bid and Retirement De-List Bid Calculation of Remaining Economic Life.

The Internal Market Monitor shall calculate the Existing Capacity Resource's remaining economic life, using evaluation periods ranging from one to five years. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the Capacity Clearing Price for the first year is equal to the Forward Capacity Auction Starting Price and (b) the expected terminal value of the resource at the end of the given evaluation period. The economic life is the maximum evaluation period in which a resource's net present value is non-negative.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an Export Bid, Permanent De-List Bid, or Retirement De-List Bid at or 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 Capacity Resource that submits a Static De-List Bid, or an Export Bid at or 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.A 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 Capacity Resource submitting a Static De-List Bid or an Export Bid, Permanent De-List Bid or Retirement De-List Bid at or above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected Capacity Performance Payments, discount rate, 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. Static De-List Bid Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all Static 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
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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:

$$\frac{\text{Cost Of Capital}}{(1 - (1 + \text{CostOfCapital})^{-\text{RemainingLife}})}$$

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. Retirement Determination Notification for Existing Capacity and Qualification Determination Notification for Existing Capacity.

(a) No later than 90 days after the Existing Capacity Retirement Deadline, the ISO shall send notification to the Lead Market Participant that submitted each Permanent De-List Bid and Retirement De-List Bid concerning the result of the Internal Market Monitor’s review conducted pursuant to Section III.13.1.2.3.2. This retirement determination notification shall not include the results of the reliability review pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5.

(b) 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 and Export Bid concerning the result of the Internal Market Monitor’s de-list bid review conducted pursuant to Section III.13.1.2.3.2. The qualification determination shall not include the results of the reliability review pursuant to Section III.13.2.5.2.5.

III.13.1.2.4.1. Participant-Elected Retirement or Conditional Treatment.

No later than ten Business Days after the issuance by the ISO of the retirement determination notification described in Section III.13.1.2.4(a), a Lead Market Participant that submitted a Permanent De-List Bid or Retirement De-List Bid may make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b). If the Lead Market Participant does not make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b), the prices provided by the Internal Market Monitor in the retirement determination notifications shall be the finalized prices used in the Forward Capacity Auction as described in Section III.13.2.3.2(b) (unless otherwise directed by the Commission).

(a) A Lead Market Participant may elect to retire the resource, or portion thereof, for which it has submitted a Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will not be subject to reliability review and will be retired pursuant to Section III.13.2.5.2.5.3(a); provided, however, that when making the retirement election pursuant to this Section III.13.1.2.4.1(a) the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

(b) A Lead Market Participant may elect conditional treatment for the Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will be treated as described in Section III.13.2.3.2(b)(ii), Section III.13.2.5.2.1, and Section III.13.2.5.2.5.3; provided, however, that in making this election the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

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.13.1.1.2 (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 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 established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff.

An Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be included in the FCM (1) after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Forward Capacity Market qualification requirements or (2) after it has met the requirements of an Elective Transmission Upgrade with Long Lead Time Facility treatment pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff. An external node for such an Elective Transmission Upgrade will be modeled for participation in the Forward Capacity Market after the Import Capacity Resource meets the requirements to participate in the FCA. The Qualified Capacity of an Import Capacity Resource associated with an Elective Transmission Upgrade shall not exceed the Capacity Network Import Interconnection Service Interconnection Request. In order for an Elective Transmission Upgrade to maintain its Capacity Network Import Interconnection Service, an associated Import Capacity Resource must meet the Forward Capacity

Market qualification requirements and offer into each Forward Capacity Auction. Otherwise, the Capacity Network Import Interconnection Service will revert to Network Import Interconnection Service for the portion of the Capacity Network Import Interconnection Service for which no Import Capacity Resource is offered into the Forward Capacity Auction and the Elective Transmission Upgrade's Interconnection Agreement will be revised. The provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election, shall apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade seeking to reestablish Capacity Network Import Interconnection Service if the threshold to be treated as a new resource in Section III.13.1.1.1.4 is met. If the threshold to be treated as a new increment in Section III.13.1.1.1.3 is met, only the increment will be eligible for the provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election.

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Retirement 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.A Qualification Process for Existing Import Capacity Resources that are not associated with an Elective Transmission Upgrade with Capacity Network Import Interconnection Service.

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) The Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply.

(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 15 Business Days prior to the Existing Capacity Retirement 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.13.1.3.3.B. Qualification Process for Existing Import Capacity Resources that are associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service.

Existing Import Capacity Resources associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be subject to the same qualification process as Existing Generating Capacity Resources as described in Section III.13.1.2.3, except the Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

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.

(a) For each New Import Capacity Resource, the Project Sponsor 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 the contract period including the entire Capacity Commitment Period, 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 Project Sponsor must specify the interface over which the capacity will be imported. The Project Sponsor must indicate whether the import is associated with any investment in transmission that increases New England's import capability or is associated with an Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff. The Project Sponsor must submit a contract confirming its association with the Elective Transmission Upgrade Interconnection Customer and the ISO will confirm that relationship. If the import will be backed by a single new External Resource, the Project Sponsor 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).

(b) To qualify for Capacity Commitment Periods prior to the Capacity Commitment Period associated with the Forward Capacity Auction for which the import capacity is qualifying, the Project Sponsor must submit documentation of one or more one-year contracts for each prior Capacity Commitment Period, 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(s); the Project Sponsor must also satisfy the relevant requirements of Sections III.13.1.3.5.1(a) , III.13.1.3.5.2, III.13.1.9, and III.13.3.1.1.

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 and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, 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 Project Sponsor shall instead submit a description of how the New Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets, 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 apply in addition to the requirement that the Project Sponsor submit a description of how the New Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the Project Sponsor, 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 and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, 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 Project Sponsor 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.

If the New Import Capacity Resource will be backed by an external Control Area and the capacity will be imported over an Elective Transmission Upgrade and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, 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 apply in addition to the requirement that the Project Sponsor 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 for the length of the multi-year contract.

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 Project Sponsor 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 Project Sponsor 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 Project Sponsor 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 only apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request. All other 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.

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 unless the capacity will be imported over an Elective Transmission Upgrade pursuing Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.3.5.5.A. Cost Information.

The offer information described in Section III.13.1.1.2.2.3 and Section III.A.21.2 may be submitted in the form of a curve (up to five price-quantity pairs) associated with a specific New Import Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each 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.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources.

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.

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.1.2.8, a Lead Market Participant with a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade) that submitted a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5 may: (a) lower the requested offer price of any price-quantity pair submitted to the ISO pursuant to Section III.13.1.1.2.2.3, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or (b) withdraw any price-quantity pair of a requested offer price.

III.13.1.3.5.8. Rationing Election.

New Import Capacity Resources are subject to rationing except New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request, which are eligible for the rationing election described in Section III.13.1.1.2.2.3(b).

III.13.1.4. Demand Capacity Resources.

~~III.13.1.4.1. Demand Resources.~~

To participate in a Forward Capacity Auction as a Demand Capacity Resource, a resource must meet the requirements of this Section III.13.1.4.1. ~~Each~~The amount of capacity offered by a Demand Capacity Resource shall be a minimum of 100 kW ~~aggregated in a Dispatch Zone.~~ An Active Demand Capacity Resource comprises one or more Demand Response Resources located in a single Dispatch Zone. An On-Peak Demand Resource or Seasonal Peak Demand Resource comprises one or more Assets located in a single Load Zone. ~~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 Capacity Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Capacity Resource. Demand Capacity Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

~~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 Permanent De List Bid or Retirement De List Bid pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that neither a Permanent De List Bid nor a Retirement De List Bid shall 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 Section III.13.1.2.3.1.1.~~

III.13.1.4.1.2. Definition of New Demand Capacity Resources.

A New Demand Capacity Resource is an Active Demand Capacity Resource that has not cleared in a previous Forward Capacity Auction, and On-Peak Demand Resource consisting of measures that have not been in service prior to the ~~applicable~~ Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction, or a Seasonal Peak Demand Resource consisting of measures that have not been in service prior to the Existing Capacity Qualification Deadline of the applicable 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 Capacity Resource that has previously been defined as an Existing Demand Capacity Resource shall be considered a New Demand Capacity Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

~~III.13.1.4.1.3. ——— Demand Reduction Values.~~

~~A Demand Reduction Value is a quantity of reduced demand produced by a Demand Resource and is calculated pursuant to Sections III.13.1.4.1.3.1 and III.13.1.4.1.3.2.~~

~~III.13.1.4.1.3.1 ——— 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.13.1.4.1.3.1.1. ——— 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.13.1.4.1.3.1.2. ——— 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.13.1.4.1.3.2. 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.13.1.4.1.3.2.1. 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.13.1.4.1.3.2.2. 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.13.1.4.1.14. Qualified Capacity of Qualification Process for New Demand Capacity Resources.

For Forward Capacity Auctions a New Demand Capacity Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's ~~Demand Reduction Values~~ estimated demand reduction value as submitted and reviewed pursuant to this Section III.13.1.4. The FCA Qualified Capacity for a New Demand Capacity 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.

(a) For a resource to qualify as a New Demand Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit estimated demand reduction values and supporting information in the New Demand Capacity Resource Show of Interest Form as described in Section III.13.1.4.1.1.1. Second, the Project Sponsor must submit a New Demand Capacity Resource Qualification Package as described in Section III.13.1.4.1.1.2.

(b) For a resource to qualify as a New Demand Capacity Resource that is an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Project Sponsor must in addition submit, as part of the New Demand Capacity Resource Qualification Package, a Measurement and Verification Plan providing the documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.1.4 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.13.1.4.1.5. Initial Analysis for Certain New Demand Resources

~~For each New Demand Resource that is a Demand Response Capacity 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.13.1.4.1.21.1. New Demand Capacity Resource 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 Capacity Resource, the Project Sponsor must submit to the ISO a New Demand Capacity

Resource Show of Interest Form as described in this Section III.13.1.4.1.21.1 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 Capacity Resource Show of Interest Form is available on the ISO website.

~~(a)~~ —A completed New Demand Capacity Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Capacity Resource ~~project~~ will be located; the Dispatch Zone within which an Active Demand ~~Response~~ Capacity Resource will be located; estimated summer and winter ~~Demand Reduction Values~~ 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~~ demand reduction value of the Demand Capacity Resource ~~project (for an Active Demand Capacity Resource, this estimate must be consistent with the baseline calculation methodology in Section III.8.2)~~; 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 Capacity Resource type (Active Demand Capacity Resource, On-Peak Demand Resource, or Seasonal Peak Demand Resource, ~~or Demand Response Capacity Resource~~); brief Demand Capacity 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 Capacity Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity 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 Capacity 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 Retirement 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.13.1.4.1.1.22.2. ~~————~~ New Demand Capacity Resource 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 Capacity Resource, the Project Sponsor must submit a New Demand Capacity Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Capacity Resource Qualification Package shall conform to the requirements of this Section

III.13.1.4.1.21.2. 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.13.1.4.1.1.2.12.2.2. Source of Funding.

The Project Sponsor must provide in the New Demand Capacity Resource Qualification Package the 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; ~~and a~~ completed ISO credit application.

III.13.1.4.1.1.2.22.2.3. Measurement and Verification Plan.

For ~~all On-Peak~~ Demand Resources and Seasonal Peak other than Demand ~~Response Capacity~~ Resources, the Project Sponsor must provide in the New Demand Capacity Resource Qualification Package a Measurement and Verification Plan ~~which that~~ complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 ~~and III.8B~~ and the ISO New England Manuals.

III.13.1.4.1.1.2.32.2.4. Customer Acquisition Plan.

A Project Sponsor with more than a single customer must include in the New Demand Capacity Resource Qualification Package ~~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.13.1.4.1.1.2.42.2.4.1. Critical Path Schedule for a Demand Capacity Resource with a Demand Reduction Value of at Least 5 MW at a Single Retail Delivery Point. 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 Project Sponsor of a For individual Distributed Generation projects and Demand Capacity Resource projects from a single facility with a dDemand rReduction yValue greater than or equal to of at least 5 MW at a single Retail Delivery Point shall provide in the New Demand Capacity Resource Qualification Package the a 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.13.1.4.1.1.2.52.2.4.2. Critical Path Schedule for a Demand Capacity Resource with All Retail Delivery Points Having a Demand Reduction Value of Less Than 5 MW Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

~~The Project Sponsor of a A critical path schedule for Demand Capacity Resource with all Retail Delivery Points having a demand reduction value of less than 5 MW projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall provide in the New Demand Capacity Resource Qualification Package a critical path schedule be~~ comprised of a delivery schedule of the share of total offered ~~dDemand Rreduction yValue~~ achieved as of target dates ~~as follows which are:~~ (i) ~~Tthe~~ cumulative percentage of total ~~DdDemand rReduction yValue~~ 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) ~~Tthe~~ cumulative percentage of total ~~DdDemand Rreduction yValue~~ 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 ~~D~~demand ~~R~~reduction ~~V~~value must be complete.

III.13.1.4.1.1.2.6.2.2.4.3: Additional Critical Path Schedule Requirement For ~~Demand Resource~~ Project Sponsors 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 Capacity Resource Qualification Package a cumulative percentage of demand reduction value achieved ~~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 ~~D~~demand ~~R~~reduction ~~V~~values, and expected measure installation date; provided, however, that a ~~Demand Resource~~ Project Sponsor targeting customer facilities with under 10 kW of ~~D~~demand ~~R~~reduction ~~V~~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.13.1.4.1.1.2.7.2.2.5: Capacity Commitment Period Election.

In the New Demand Capacity Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Capacity 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 Capacity Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Capacity Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Capacity 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 Capacity Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Capacity 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.13.1.4.1.1.2.7-2.5.

~~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 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.13.1.4.1.1.2.8.2.4. ———Offers Information From New Demand Capacity Resources.

(a) All New Demand 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 Demand Capacity 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.

(b) The Project Sponsor for a New Demand Capacity Resource must indicate in the New Demand Capacity Resource Qualification Package if an offer from the New Demand Capacity 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.13.1.4.1.1.3. Initial Analysis for Active Demand Capacity Resources.

For each New Demand Capacity Resource that is an Active Demand Capacity Resource, the ISO shall perform an analysis based on the information provided in the New Demand Capacity 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 Capacity 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 Capacity Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.1.4. Consistency of the New Demand Capacity Resource Qualification Package and New Demand Capacity Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Capacity Resource Qualification Package for consistency with its New Demand Capacity Resource Show of Interest Form. The New Demand Capacity Resource Qualification Package may not contain material changes relative to the New Demand Capacity 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 Capacity 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 Active Demand Capacity 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); or (vi) a misrepresentation of the interconnection status of a Distributed Generation project.

~~III.13.1.4.2.5. Notification of Qualification for Demand Resources.~~

III.13.1.4.1.1.5.2.5.1. Evaluation of New Demand Capacity Resource Qualification Materials.

The ISO shall review the information submitted by ~~Existing Demand Resources and~~ New Demand Capacity 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 Capacity 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 Capacity 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 Capacity Resources includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule submitted by New Demand Capacity 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 Capacity Resource are satisfied; and

(e) whether, in the case of a New Demand Capacity Resource that is an On-Peak Demand Resource or Seasonal Peak Demand Resource, 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 20 Business Days before the Existing Capacity Retirement 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 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, Retirement 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(e) 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.13.1.4.1.1.6.2.5.3. Qualification Determination Notification of Qualification for New Demand Capacity 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 Capacity Resource indicating whether the New Demand Capacity Resource has been accepted for participation in the Forward Capacity Auction.

~~(a) **III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.**~~

~~For a New Demand Capacity Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Capacity Resource type and the Demand Capacity Resource's summer and winter Demand Reduction Value and summer and winter Qualified Capacity, which shall be the ISO-determined summer and winter demand reduction value increased by average avoided peak transmission and distribution losses (that is, eight percent). Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.~~

~~(a) **III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.**~~

~~(b) For a New Demand Capacity 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.13.1.4.2. Definition of Existing Demand Capacity Resources.

Demand Capacity Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Capacity Resources, shall be Existing Demand Capacity Resources. Existing Demand Capacity Resources shall include and are limited to Demand Capacity 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 this Section III.13.1.4, Existing Demand Capacity 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 Capacity Resources shall be subject to Section III.13.1.2.2.5.2. An On-Peak Demand Resource or Seasonal Peak Demand Resource may not include in its demand reduction value a measure whose Measure Life will expire before the beginning of the associated Capacity Commitment Period.

III.13.1.4.2.1. Qualified Capacity Notification for Existing Demand Capacity Resources.

(a) For each Existing Demand Capacity Resource, the ISO will notify the Resource's Lead Market Participant no later than 20 Business Days before the Existing Capacity Retirement Deadline of: the Demand Capacity Resource type; summer and winter Qualified Capacity (which shall be the summer and winter demand reduction value increased by average avoided peak transmission and distribution losses);

the Load Zone in which the Demand Capacity Resource is located; and, for Active Demand Capacity Resources, the Dispatch Zone in which the resource is located.

(b) If the Lead Market Participant believes that the ISO's assessment of the Qualified Capacity is inaccurate, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification.

(c) If a Market Participant with an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource wishes to change its Demand Capacity Resource type, the Market Participant must submit an Updated Measurement and Verification Plan to reflect the change in its resource type. 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 Capacity Resource type may not be changed during the Capacity Commitment Period.

(d) A Market Participant with an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource may provide an Updated Measurement and Verification Plan as described in Section III.13.1.4.3.1.2 that complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification.

(e) If an Existing Demand Capacity Resource is not submitting a Static De-List Bid, Permanent De-List Bid, or Retirement 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.

III.13.1.4.2.2. Existing Demand Capacity Resource De-List Bids.

An Existing Demand Capacity Resource may submit a Permanent De-List Bid or Retirement De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.5 no later than the Existing Capacity Retirement Deadline or a Static De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.1 no later than the Existing Capacity Qualification Deadline, provided, however, that no de-list bid shall be used as a mechanism to inappropriately qualify Assets associated with Existing Demand Capacity Resources as New Demand Capacity Resources.

III.13.1.4.3. Measurement and Verification Applicable to ~~All~~ On-Peak Demand Resources and Seasonal Peak Demand Resources.

To demonstrate the ~~D~~demand ~~R~~reduction ~~V~~value of an On-Peak Demand Resource ~~project, or Seasonal Peak Demand Resource as defined in Section III.13.1.4.1, all the Project Sponsor or Market Participant of such a Demand R~~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, ~~and Section III.8B~~ and the ISO New England Manuals. ~~Demand Response Capacity Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Section III.8B, Section III.13.6.1.5.4, 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.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 an On-Peak Demand Resource ~~or Seasonal Peak Demand Resource projects~~ in reducing demand coincident with Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours such that the reported monthly ~~D~~demand ~~R~~reduction ~~V~~value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manuals ~~and ISO New England Operating Procedures on Measurement and Verification of Demand Reduction Value from Demand Resources~~. The Measurement and Verification Documents shall serve as the basis for the claimed ~~D~~demand ~~R~~reduction ~~V~~value of an On-Peak Demand Resource ~~or Seasonal Peak Demand Resource project~~. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved ~~D~~demand ~~R~~reduction ~~V~~value of the On-Peak Demand Resource ~~project or Seasonal Peak Demand Resource~~. The Measurement and Verification Documents shall contain a projection of the On-Peak Demand Resource's ~~or Seasonal Peak Demand Resource's project's~~ ~~D~~demand ~~R~~reduction ~~V~~value for each month of the Capacity Commitment Period and over the expected Measure ~~Livesfe of associated~~

with the Demand Capacity Resources project. An On-Peak Demand Resource's or Seasonal Peak 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. If an On-Peak Demand Resource or Seasonal Peak Demand Resource includes Distributed Generation, the Measurement and Verification Documents must describe the individual metering or metering protocol used to monitor and verify the output of the Distributed Generation, consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals.

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 ~~D~~emand ~~R~~eduction ~~V~~alue from eligible pre-existing measures and new measures, and the Project Sponsor's total ~~D~~emand ~~R~~eduction ~~V~~alue 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 for an On-Peak Demand Resource or a Seasonal Peak Demand Resource 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 ~~D~~emand ~~R~~eduction ~~V~~alue of the On-Peak Demand Resource or

~~Seasonal Peak 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 for an On-Peak Demand Resource or a Seasonal Peak Demand Resource may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand ~~Capacity~~ 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 ~~claimed D~~ demand ~~R~~reduction ~~V~~value ~~and or~~ the Demand ~~Capacity~~ 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 ~~Capacity~~ 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 and~~ Seasonal Peak Demand Resources shall submit no less frequently than once per year, a statement certifying that the Demand ~~Capacity~~ 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 ~~On-Peak~~ Demand Resources ~~and Seasonal Peak Demand Resources projects~~ targeting customer facilities with greater than or equal to 10 kW of ~~D~~ demand ~~R~~reduction ~~V~~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 ~~d~~ demand ~~R~~reduction ~~V~~values. For ~~On-~~

~~Peak Demand Resources and Seasonal Peak Demand Resources projects~~ targeting customer facilities with under 10 kW of ~~D~~emand ~~R~~eduction ~~V~~alue 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 ~~D~~emand ~~R~~eduction ~~V~~alue per facility, or shall maintain records of aggregated ~~D~~emand ~~R~~eduction ~~V~~alue 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 Capacity 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 and Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, in its Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in 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 and Demand Response Capacity 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.~~

~~All Demand Response Assets must be metered at the Retail Delivery Point.~~

~~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.13.1.4.3.32. 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 or Lead Market Participant to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

~~III.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. [Reserved.]~~

~~III.13.1.4.5. [Reserved.]~~

~~III.13.1.4.6. 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 of Demand Response Capacity 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.13.1.4.7. ——— Capacity Values.**~~

~~**III.13.1.4.7.1. — 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.13.1.4.1.3 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.13.1.4.7.2. — 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 or Demand Resource Seasonal Peak 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.13.1.4.8. ——— [Reserved.]**~~

~~**III.13.1.4.9. — [Reserved.]**~~

~~**III.13.1.4.10. ——— Providing Information On Demand Response Capacity 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, 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.13.1.4.1.1.6.2.4.5.3. 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 Capacity Resource, April through November where the summer resource is a Demand Capacity

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 [Capacity](#) Resource, December through March where the summer resource is a Demand [Capacity](#) 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.~~1.1.2.72.2.5~~) 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 [Capacity](#) 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) [Reserved.]

(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 five 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 [Capacity](#) 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 FCM 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 Capacity Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.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 Capacity Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, a Retirement 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, retire 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 and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid and Retirement De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.
- (b) The quantity 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) No later than three Business Days after the Existing Capacity Retirement Deadline, the ISO shall post on its website information concerning Permanent De-List Bids and Retirement De-List Bids.

(f) The name of each Lead Market Participant submitting Static De-List Bids, Export Bids, and Administrative Export De-List Bids, as well as the number and type of such 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(b), 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, Permanent De-List Bids, and Retirement 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.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Capacity Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Resources) and New Demand Capacity Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the FCM Deposit by the Project Sponsor for a New Generating Capacity Resource or New Demand Capacity 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 Capacity Resource in the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the FCM Deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Capacity Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Capacity Resource clears in the Forward Capacity Auction, financial assurance required prior to the auction pursuant to FAP 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 Capacity Resource clears in the Forward Capacity Auction, the financial assurance required prior to the auction pursuant to FAP will be released 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 Capacity Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Capacity 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 Capacity Resource: (i) fails to provide the required financial assurance as described in the ISO New England Financial Assurance Policy 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 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 Capacity 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 Capacity Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited.

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 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 Section III.13 shall be used to reduce charges 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 or will be delivered over an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff 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 or the Elective Transmission Upgrade 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 Capacity 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, 23 or 25 of Section II of the Transmission, Markets and Services Tariff or where a resource modification does not require a revision to the Interconnection Agreement.

<p>New Generating <u>Capacity Resources</u> \geq 20 MW or an Import Capacity Resource associated with an Elective Transmission Upgrade that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff</p>	<p>New Generating <u>Capacity Resources</u> $<$ 20 MW and \geq 2 MW</p>	<p>Imports and New Demand <u>Capacity Resources</u> (including Distributed Generation)</p>		<p>New Generating <u>Capacity Resources</u> $<$ 2 MW</p>
<p><i>Including Up-rates, Re-powering, Environmental</i></p>	<p><i>Including Up-rates, Re-powering, Environmental</i></p>			

<i>Compliance & Intermittent Power Resources</i>	<i>Compliance & Intermittent Power Resources</i>			
\$25,000	\$7,500	\$1,000		\$500
<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>	<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>			
\$15,000	\$6,500	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 **Capacity** 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 Capacity 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.

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 Existing Capacity Retirement Deadline will be in March, approximately four years and three months before the beginning of the Capacity Commitment Period;

- (c) the New Capacity Show of Interest Submission Window will be in April , approximately four years and two months before the beginning of the Capacity Commitment Period;
- (d) the Existing Capacity Qualification Deadline will be in June, approximately four years before the beginning of the Capacity Commitment Period;
- (e) 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
- (f) 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.

Existing Capacity Retirement Deadline	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
March (X-4)	April (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.13.1.4.21.1.2.57) 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.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

- (i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);
- (ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at \$7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

- (iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

- (1) at prices above \$7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;
- (2) at prices below \$7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between \$7.03/kW-month and \$0.00/kW-month and determined by the following quantities:
 - (a) At the price of \$0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.
 - (b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at \$7.03/kW-month, the quantity shall be the lesser of:
 - 1. 35,437 MW; and
 - 2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month;
 - (c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at \$7.03/kW-month, the quantity shall be the lesser of:
 - 1. 35,090 MW; and
 - 2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month;
 - (d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at \$7.03/kW-month, the quantity shall be the lesser of:
 - 1. 34,865 MW; and
 - 2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month

(3) a price of \$7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the amount of capacity for which the Capacity Zone Demand Curve specifies a price of \$0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative \$0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.**

- (i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an

investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E , respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be p_1, p_2, \dots, p_m , where $P_S > p_1 > p_2 > \dots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be q_1, q_2, \dots, q_m . Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E , shall be taken to be:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \leq p_1, \\ q_2, & \text{if } p_3 < p \leq p_2, \\ \dots & \dots, \\ q_m, & \text{if } p \leq p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic Delist Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five

prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be bid into the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be

included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to

Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources.** Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Capacity Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same

manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.12.2.57 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 a Dynamic De-List 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. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, 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.

(e) **Repowering.** Offers and bids associated with a resource participating 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) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics.** Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

- (1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);
- (2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);
- (3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:
 - (i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits), or;
 - (ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;
- (4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:
 - (i) that interface's approved capacity transfer limit (net of tie benefits), or;
 - (ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

- (1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;
- (2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then the auctioneer shall publish the quantity of capacity in the Capacity Zone from Demand Capacity Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone.**

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price, and also shall publish the quantity of capacity from Demand Capacity Resources by type at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones.** For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

- (1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero, and;
- (2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the export-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-

constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and the quantity of capacity in the Capacity Zone from Demand Capacity Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-

TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is \$11.35/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is \$8.04/kW-month.

CONE and Net CONE shall be recalculated using updated data coincident with the recalculation of Offer Review Trigger Prices pursuant to Section III.A.21.1.2. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e). Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by \$0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the bid has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated if either of the following conditions is met in the initial auction clearing process: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation); or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation) and the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price. The second run of the auction-clearing process: (i) excludes all Proxy De-List Bid(s), (ii) includes the offers and bids of resources that did not receive a Capacity Supply Obligation in the first run of the auction-clearing process, and (iii) includes the capacity of resources, or portion thereof, that received a Capacity Supply Obligation in the first run of the auction-clearing process. The second run of the auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.12.2.75) that receive a Capacity Supply Obligation as a result of the first run of the auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.21.1.2.57) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity

Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Economic Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. Reliability Review.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid to determine whether the capacity associated with that de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station.. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. De-list bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) Where a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction.

(c) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject the de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability. Resources that submitted

Permanent De-List Bids or Retirement De-List Bids shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii)).

(g) If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1.

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List

Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the “just and reasonable” standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource’s Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the

Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability.** If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Capacity Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO:** A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the

Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission:** In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the Capacity Commitment Period for which the Retirement De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: submitted a Retirement De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III.13.1.2.3.1.5(d); elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction; or, for a resource, or portion thereof, that submitted a Permanent De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless 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. The interconnection rights, or relevant portion thereof, for the resource will

terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the Capacity Commitment Period for which its Permanent De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: submitted a Permanent De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III.13.1.2.3.1.5(d); was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) 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.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity

Clearing Price for each import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. Capacity Clearing Price Floor.

In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below \$3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches \$3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

- (i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to \$3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.
- (ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).
- (iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).
- (iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource's payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.
- (v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply 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 Section III.13.1.1.2.2.4 or Section III.13.1.4.~~21.1.2.75~~.

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Incremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity,

then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

- (a) [Reserved.]
- (b) If multiple projects may be rationed, they will be rationed proportionately.
- (c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.
- (d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources) shall be cleared.

III.13.3. Critical Path Schedule Monitoring.

III.13.3.1. Resources Subject to Critical Path Schedule Monitoring.

III.13.3.1.1. New Resources Electing Critical Path Schedule Monitoring.

A Project Sponsor that submits a critical path schedule for a New Capacity Resource in the qualification process may request that the ISO monitor that resource's compliance with its critical path schedule in accordance with the provisions of this Section III.13.3. The ISO will monitor the New Capacity Resource's compliance from the time the ISO approves the request until the resource achieves Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4(c), or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

In addition, a Lead Market Participant with a New Import Capacity Resource backed by one or more existing External Resources seeking to qualify for Capacity Commitment Period(s) prior to the Capacity Commitment Period associated with the Forward Capacity Auction for which it is qualifying must request monitoring under this Section III.13.3.1.1.

A request under this Section III.13.3.1.1 must be made in writing no later than five Business Days after the deadline for submission of the FCM Deposit pursuant to Section III.13.1.9.1.

III.13.3.1.2. New Resources Clearing in the Forward Capacity Auction.

For each new resource required to submit a critical path schedule in the qualification process, including but not limited to a New Generating Capacity Resource (pursuant to Section III.13.1.1.2.2), a New Import Capacity Resource backed by a new External Resource (pursuant to Section III.13.1.3.5), or a New Demand Capacity Resource (pursuant to Section III.13.1.4), if capacity from that resource clears in the Forward Capacity Auction, then the ISO shall monitor that resource's compliance with its critical path schedule in accordance with the provisions of this Section III.13.3 (regardless of whether the Project Sponsor requested monitoring pursuant to Section III.13.3.1.1) from the time that the Forward Capacity Auction is conducted until the resource achieves Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4(c), or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

III.13.3.1.3. New Resources Not Offering or Not Clearing in the Forward Capacity Auction.

If no capacity from a new resource that was required to submit a critical path schedule in the qualification process clears in the Forward Capacity Auction, or if such a resource does not submit an offer in the Forward Capacity Auction, then the ISO shall not monitor that resource's compliance with its critical path schedule after the Forward Capacity Auction unless the Project Sponsor previously requested pursuant to Section III.13.3.1.1 that the ISO continue to monitor that resource's compliance with its critical path schedule. However, if a New Generating Capacity Resource participated but did not clear in the Forward Capacity Auction either as: (i) a Conditional Qualified New Resource, or (ii) a New Generating Capacity Resource with a higher priority in the queue and overlapping interconnection impacts with a Conditional Qualified New Resource, the ISO will not continue to monitor that resource's compliance with its critical path schedule even if that resource requested critical path schedule monitoring pursuant to Section III.13.3.1.1.

III.13.3.2. Quarterly Critical Path Schedule Reports.

For each new resource that is being monitored for compliance with its critical path schedule, the Project Sponsor for that resource must provide a written critical path schedule report to the ISO no later than five Business Days after the end of each calendar quarter. If the Project Sponsor does not provide a written critical path schedule report to the ISO by the fifth Business Day after the end of the calendar quarter, then the ISO shall issue a notice thereof to the Project Sponsor. If the Project Sponsor fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.13.3.4(c). Each critical path schedule report shall include the following:

III.13.3.2.1. Updated Critical Path Schedule.

The critical path schedule report must include a complete updated version of the critical path schedule as described in Section III.13.1.1.2.2.2, dated contemporaneously with the submission of the critical path schedule report. The updated critical path schedule should clearly indicate if the Project Sponsor is proposing to change any of the milestones or dates from the previously submitted version of the critical path schedule, and must include an explanation of any such proposed changes. In the critical path schedule report, the Project Sponsor should also explain in detail any proposed changes to the project design and the potential impact of such changes on the amount of capacity the resource will be able to provide.

III.13.3.2.2. Documentation of Milestones Achieved.

(a) For all new resources except for Demand ~~Capacity~~ Resources ~~projects~~ installed at multiple facilities and Demand ~~Capacity~~ Resources ~~projects~~ from a single facility with a ~~d~~Demand ~~R~~reduction ~~V~~yalue of less than 5 MW (discussed in Section III.13.3.2.2(b)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Major Permits.** For each major permit described in the critical path schedule, the Project Sponsor shall provide documentation showing that the permit was applied for and obtained as described in the critical path schedule. For permit applications, this documentation could include a dated copy of the permit application or cover letter requesting the permit. For approved permits, this documentation could include a dated copy of the approved permit or letter granting the permit from the permitting authority.

(ii) **Project Financing Closing.** The Project Sponsor shall provide documentation showing that the sources of financing identified in the critical path schedule have committed to provide the amount of financing described in the critical path schedule. This documentation could include copies of commitment letters from the sources of financing.

(iii) **Major Equipment Orders.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was ordered as described in the critical path schedule. This documentation should include a copy of a dated confirmation of the order from the manufacturer or supplier. This documentation should confirm scheduled delivery dates consistent with milestone Section III.13.3.2.2(a)(vi).

(iv) **Substantial Site Construction.** The Project Sponsor shall provide documentation showing that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs.

(v) **Major Equipment Delivery.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was delivered to the project site and received as preliminarily acceptable as described in the critical

path schedule. This documentation should include a copy of a dated confirmation of delivery to the project site.

(vi) **Major Equipment Testing.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the component was tested, including major systems testing as appropriate for the specific technology as described in the critical path schedule, and that the test results demonstrate the equipment's suitability to allow, in conjunction with other major component, subsequent Commercial Operation of the project in accordance with the amount of capacity obligated from the resource in the Capacity Commitment Period in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning.** The Project Sponsor shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity obligated from the resource in the Capacity Commitment Period. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Project Sponsor is not required to provide documentation of Commercial Operation to the ISO as part of the ISO's critical path schedule monitoring. The ISO shall confirm that the resource has achieved Commercial Operation as described in the critical path schedule through the resource's compliance with the other relevant requirements of the Transmission, Markets and Services Tariff and the ISO New England System Rules.

(ix) **Transmission Upgrades.** If during the qualification process it was determined that, because of overlapping interconnection impacts, transmission upgrades are needed for the new resource to complete its interconnection, then the Project Sponsor shall provide documentation showing that the transmission upgrades have been completed.

(b) For Demand Capacity Resources ~~projects~~ installed at multiple facilities and Demand Capacity Resources ~~projects~~ from a single facility with a ~~D~~emand ~~R~~eduction ~~V~~alue of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating

that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion.** The Project Sponsor shall provide documentation showing the total offered ~~D~~demand ~~R~~reduction ~~V~~value achieved as of target dates which are: (a) the cumulative percentage of total ~~d~~demand ~~R~~reduction ~~V~~value achieved on target date 1 occurring five weeks prior to the first Forward Capacity Auction after the Forward Capacity Auction in which the Demand ~~Capacity~~ Resource supplier's capacity award was made; (b) the cumulative percentage of total ~~D~~demand ~~R~~reduction ~~V~~value achieved on target date 2 occurring five weeks prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Demand ~~Capacity~~ Resource supplier's capacity award was made; and (c) target date 3 which is the date the resource is expected to achieve commercial operation, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100 percent of the total ~~D~~demand ~~R~~reduction ~~V~~value must be complete.

(ii) **Pipeline Analysis.** If the Project Sponsor proposes in its New Demand ~~Capacity~~ Resource Qualification Package a cumulative percentage of demand reduction value achieved ~~Percent of Total Demand Reduction Value Complete~~ that is 30 percent or less by the second critical path schedule target date, then the Project Sponsor shall provide a pipeline analysis to the ISO as specified in Section III.13.1.4. ~~1.1.2.62-2.4.3~~ of Market Rule 1.

(iii) **Additional Requirements.** For each customer and each prospective customer the Project Sponsor shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's ~~asset-Asset~~ has been registered with the ISO, then the Project Sponsor shall also provide the ~~asset-Asset~~ identification number.

III.13.3.2.3. Additional Relevant Information.

The Project Sponsor must include in the critical path schedule report any other information regarding the status or progress of the project or any of the project milestones that might be relevant to the ISO's evaluation of the feasibility of the project being built in accordance with the critical path schedule or the feasibility that the project will meet the requirement that the project achieve Commercial Operation no later than the start of the relevant Capacity Commitment Period.

III.13.3.2.4. Additional Information for Resources Previously Counted As Capacity.

For each resource participating 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 or New Demand Capacity Resource pursuant to Section III.13.1.4.1.2 and clearing in that auction, the Project Sponsor must provide information in the critical path schedule report demonstrating: (a) the shedding of the resource's Capacity Supply Obligation in accordance with the provisions of Section III.13.1.1.2.2.5(c); and (b) that the relevant cost threshold (described in Sections III.13.1.1.1.2, III.13.1.1.1.3, and III.13.1.1.1.4) is being met.

III.13.3.3. Failure to Meet Critical Path Schedule.

If the ISO determines that any critical path schedule milestone date has been missed, or if the Project Sponsor proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.13.3.2.1), then the ISO shall consult with the Project Sponsor to determine the impact of the missed milestone or proposed revision, and shall determine a revised date for the milestone and for any other milestones affected by the change including Commercial Operation of the project. If a milestone date is revised for any reason, the ISO may require the Project Sponsor to submit a written report to the ISO on the fifth Business Day of each month until the revised milestone is achieved detailing the progress toward meeting the revised milestone. If the Project Sponsor does not provide a written critical path schedule report to the ISO on the fifth Business Day of a month, then the ISO shall issue a notice thereof to the Project Sponsor. If the Project Sponsor fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.13.3.4(c). Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.13.3.2.

III.13.3.4. Covering Capacity Supply Obligation where Resource will Not Achieve Commercial Operation by the Start of the Capacity Commitment Period.

Except as described in Section III.13.3.7, if as a result of milestone date revisions, the Commercial Operation milestone date is after the start of any Capacity Commitment Period in which the resource has a Capacity Supply Obligation (except for a New Generating Capacity Resource that has cleared in the Forward Capacity Auction and 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), then the Project Sponsor must take actions to cover the entire Capacity Supply Obligation for the portion of the Capacity Commitment Period for which the project will not have achieved Commercial Operation, as follows:

(a) The Project Sponsor may cover its Capacity Supply Obligation through reconfiguration auctions as described in Section III.13.4 or one or more Capacity Supply Obligation Bilaterals, subject to the satisfaction of the requirements in Section III.13.5.

(b) If, by the time demand bids are due for the third annual reconfiguration auction for the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, the Project Sponsor has not covered its full Capacity Supply Obligation for the portion of the Capacity Commitment Period for which the project will not have achieved Commercial Operation, then the ISO shall submit a demand bid in that annual reconfiguration auction on the Project Sponsor's behalf for a quantity equal to the largest monthly Capacity Supply Obligation for the Capacity Commitment Period that has not been covered, at the Forward Capacity Auction Starting Price (or, for any demand bid submitted by the ISO in the third annual reconfiguration auction associated with the seventh Capacity Commitment Period, at \$12.11/kW-month), with all payments, charges, rights, obligations, and other results associated with such demand bid applying to the Project Sponsor as if the Project Sponsor itself had submitted the demand bid.

(c) If the Project Sponsor fails to comply with the requirements of Sections III.13.3.2 or III.13.3.3, or if the Capacity Supply Obligation is not covered as described in Sections III.13.3.4(a) and III.13.3.4(b), or if the Project Sponsor covers the Capacity Supply Obligation for two Capacity Commitment Periods, then the ISO, after consultation with the Project Sponsor, shall have the right, through a filing with the Commission, to terminate the resource's Capacity Supply Obligation for any future Capacity Commitment Periods and the resource's right to any payments associated with that Capacity Supply Obligation in the Capacity Commitment Period, and to adjust the resource's qualified capacity for participation in the Forward Capacity Market; provided that, where a Project Sponsor voluntarily withdraws its resource from critical path schedule monitoring in accordance with Section III.13.3.6, no filing with the Commission shall be necessary to terminate the resource's Capacity Supply Obligation. Upon Commission ruling, the Project Sponsor shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation. If in these circumstances, however, the ISO does not take steps to terminate the resource's Capacity Supply Obligation and instead permits the Project Sponsor to continue to cover its Capacity Supply Obligation, such continuation shall be subject to the ISO's right to revoke that permission and to file with the Commission to terminate the resource's Capacity Supply Obligation, and subject to continued reporting by the Project Sponsor as described in this Section III.13.3.

III.13.3.5. Termination of Interconnection Agreement.

If the ISO terminates, or files with the Commission to terminate, a resource's Capacity Supply Obligation as described in Section III.13.3.4(c), the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. If the Project Sponsor continues to cover all of its Capacity Supply Obligations while challenging such termination before the Commission, it shall retain its Queue Position.

III.13.3.6. Withdrawal from Critical Path Schedule Monitoring.

A Project Sponsor may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO. The ISO also may deem a resource withdrawn from critical path schedule monitoring if the Project Sponsor does not adhere to the requirements of this Section III.13.3. Any resource withdrawn from critical path schedule monitoring shall be subject to the provisions of Section III.13.3.4.

III.13.3.7 Request to Defer Capacity Supply Obligation

A resource that has not yet achieved Commercial Operation and that is subject to critical path schedule monitoring by the ISO pursuant to this Section III.13.3 may seek to defer the applicability of its entire Capacity Supply Obligation by one year pursuant to the provisions of this Section III.13.3.7.

A Project Sponsor seeking such a deferral must notify the ISO in writing no later than the first Business Day in September of the year prior to the third annual reconfiguration auction for the Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If, after consultation with the Project Sponsor, the ISO determines that the absence of the capacity in the first Capacity Commitment Period in which the resource has a Capacity Supply Obligation, as well as in the subsequent Capacity Commitment Period, would result in the violation of any NERC or NPCC (or their successors) criteria or of the ISO New England System Rules, not solely that it may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for the Capacity Zone, then the ISO will review the specific reliability need with and seek feedback from the Reliability Committee and provide the Project Sponsor with a written determination to that effect within 30 days of the Project Sponsor's notification to the ISO.

If the ISO provides such a written determination, then the Project Sponsor may file with the Commission, no later than the first Business Day in November of the year prior to the third annual reconfiguration auction, a request to defer the applicability of its Capacity Supply Obligation by one year. Any such filing must include the ISO's written determination, and must also demonstrate that the deferral is critical to the

resource's ability to achieve Commercial Operation and that the reasons for the deferral are beyond the control of the Project Sponsor.

If the Commission approves the request, all of the rights, obligations, payments, and charges associated with the Capacity Supply Obligation described in Section III.13.6 and Section III.13.7 shall only apply beginning one year after the start of the Capacity Commitment Period in which the resource has a Capacity Supply Obligation. Notwithstanding any other provision of this Section III.13, if the resource achieves commercial operation prior to the deferred date, it will not be eligible to receive revenue in the Forward Capacity Market until the deferred date. Beginning on the deferred date, all of the rights, obligations, payments, and charges associated with the Capacity Supply Obligation shall apply, and 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) associated with the Forward Capacity Auction in which the resource cleared as a new resource shall apply for the full duration of the Capacity Supply Obligation (including multi-year elections made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.~~1.12.2.57~~). Neither the Project Sponsor, nor the ISO on the Project Sponsor's behalf, will take actions to cover the resource's Capacity Supply Obligation for the deferral period as described in Section III.13.3.4, but the other requirements of III.13.3, including all reporting requirements and the ISO's right to seek termination, shall continue to apply during the deferral period. Upon Commission approval of the deferral, the resource may not participate in any reconfiguration auctions or Capacity Supply Obligation Bilaterals for any portion of the deferral period. Beginning at 8:00 a.m. (Eastern Time) 30 days after Commission approval of the request, the Project Sponsor shall be required to provide an additional amount of financial assurance as described in Section VII.B.2.c of the ISO New England Financial Assurance Policy.

Notwithstanding any other provision of this Section III.13, if any of the resource's Capacity Supply Obligation in the deferral period was shed in a reconfiguration auction or Capacity Supply Obligation Bilateral prior to Commission approval of the deferral request, then the resource's settlements shall be adjusted by the ISO to ensure that the resource does not receive any payments associated with that transaction in excess of the charges associated with that transaction; the resource will be responsible for any charges in excess of payments.

III.13.4. Reconfiguration Auctions.

For each Capacity Commitment Period, the ISO shall conduct annual and monthly reconfiguration auctions as described in this Section III.13.4. Reconfiguration auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in reconfiguration auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Sections III.13.4.5 and III.13.4.7) to clear supply offers (i.e., offers to assume a Capacity Supply Obligation) and demand bids (i.e., bids to shed a Capacity Supply Obligation) for each Capacity Zone included in the reconfiguration auction. Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected. Resources that are able to meet the requirements in other Capacity Zones shall be allowed to clear to meet such requirements, subject to the constraints modeled in the auction.

III.13.4.1. Capacity Zones Included in Reconfiguration Auctions.

Each reconfiguration auction associated with a Capacity Commitment Period shall include each of, and only, the final Capacity Zones and external interfaces as determined through the Forward Capacity Auction for that Capacity Commitment Period, as described in Section III.13.2.3.4.

III.13.4.2. Participation in Reconfiguration Auctions.

Each supply offer and demand bid in a reconfiguration auction must be associated with a specific resource, and must satisfy the requirements of this Section III.13.4.2. All resource types may submit supply offers and demand bids in reconfiguration auctions. In accordance with Section III.A.9.2 of *Appendix A* of this Market Rule 1, supply offers and demand bids submitted for reconfiguration auctions shall not be subject to mitigation by the Internal Market Monitor. A supply offer or demand bid submitted for a reconfiguration auction shall not be limited by the associated resource's Economic Minimum Limit. Offers composed of separate resources may not participate in reconfiguration auctions. Participation in any reconfiguration auction is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of the offer and bid deadline. For annual reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 30 days prior to that deadline. No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 10 Business Days prior to that deadline. Upon issuance of the monthly bilateral results for the associated

obligation month, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that monthly auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions in which the most recently approved Winter Seasonal Claimed Capability established as of the fifth Business Day in June of the relevant Capacity Commitment Period is greater than the Winter ARA Qualified Capacity for the third annual reconfiguration auction, the ISO shall apply the greater of these two values to offer limits starting with the first monthly reconfiguration auction in the winter delivery period for the relevant Capacity Commitment Period, limited, as applicable, by the resource's CNR Capability.

III.13.4.2.1. Supply Offers.

Submission of supply offers in reconfiguration auctions shall be governed by this Section III.13.4.2.1. All supply offers in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, in dollars per kW/month. In no case may capacity associated with a Retirement De-List Bid or a Permanent De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that, or any subsequent, Capacity Commitment Period, or any portion thereof. In no case may capacity associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof.

III.13.4.2.1.1. Amount of Capacity That May Be Submitted in a Supply Offer in an Annual Reconfiguration Auction.

For each month of the Capacity Commitment Period associated with the annual reconfiguration auction, the ISO shall calculate the difference between the Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, and the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for the month. The minimum of these 12 values shall be the amount of capacity up to which a resource may submit a supply offer in the annual reconfiguration auction.

III.13.4.2.1.2. Calculation of Summer ARA Qualified Capacity and Winter ARA Qualified Capacity.

III.13.4.2.1.2.1. First Annual Reconfiguration Auction and Second Annual Reconfiguration Auction.

III.13.4.2.1.2.1.1. Generating Capacity Resources Other than Intermittent Power Resources.

III.13.4.2.1.2.1.1.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the higher of the resource's summer Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any summer Seasonal Claimed Capability values for summer periods completed after the Existing Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and where the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.1.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the higher of the resource's winter Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any winter Seasonal Claimed Capability values for winter periods completed after the Existing

Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and where the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2. Intermittent Power Resources.

III.13.4.2.1.2.1.2.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined summer Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined winter Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.3. Import Capacity Resources Backed By an External Control Area.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to its summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period.

III.13.4.2.1.2.1.3.1. Import Capacity Resources Backed by One or More External Resources.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be the greater of:

(a) the summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period; and

(b) the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October and, if submitted for a New Import Capacity Resource backed by one or more External Resources, also subject to the satisfaction of the requirements

in Sections III.13.1.3.5.1(b), III.13.1.3.5.2, and III.13.3.1.1 and the relevant financial assurance requirements as described in Section III.13.1.9 and the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.4. Demand Capacity Resources.

III.13.4.2.1.2.1.4.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined summer Qualified Capacity.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.4.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined winter Qualified Capacity.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2. Third Annual Reconfiguration Auction.

III.13.4.2.1.2.2.1. Generating Capacity Resources other than Intermittent Power Resources.

III.13.4.2.1.2.2.1.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's summer Seasonal Claimed Capability value in effect after the most recently completed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.1.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2. Intermittent Power Resources.

III.13.4.2.1.2.2.2.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the lesser of its most recently-determined summer Qualified Capacity and its summer Seasonal Claimed Capability value in effect after the most recently competed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the lesser of its most recently-determined winter Qualified Capacity and its winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.3. Import Capacity Resources.

III.13.4.2.1.2.2.3.1 Import Capacity Resources Backed by an External Control Area.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its summer Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October. For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its winter Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October.

III.13.4.2.1.2.2.3.2 Import Capacity Resources Backed by One or More External Resources.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be the lesser of:

(a) the summer Qualified Capacity and winter Qualified Capacity, respectively, as determined by the most recent Forward Capacity Auction that does not reflect a change to the Import Capacity Resource applicable to that Capacity Commitment Period; and

(b) the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October and, if submitted for a New Import Capacity Resource backed by one or more External Resources, also subject to the satisfaction of the requirements in Sections III.13.1.3.5.1(b), III.13.1.3.5.2, and III.13.3.1.1 and the relevant financial assurance requirements as described in Section III.13.1.9 and the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.4. Demand Capacity Resources.

III.13.4.2.1.2.2.4.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the lesser of: (i) its most recently-determined summer Qualified Capacity and (ii) its summer Seasonal DR Audit value or summer Passive DR Audit value in effect at the time of qualification for the third annual reconfiguration auction~~in effect after the most recently completed summer season or its Demand Resource Commercial Operation Audit performed during the most recently completed summer season, whichever is more recent.~~

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.4.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the lesser of: (i) its most recently-determined winter Qualified Capacity and (ii) its winter Seasonal DR Audit value or winter Passive DR Audit value in effect at the time of qualification for the third annual reconfiguration auction~~in effect after the most recently completed winter season or its Demand Resource Commercial Operation Audit performed during the most recently completed winter season, whichever is more recent.~~

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.3. Adjustment for Significant Decreases in Capacity.

For each month of the Capacity Commitment Period associated with the third annual reconfiguration auction, for each resource that has achieved Commercial Operation, the ISO shall subtract the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, from the amount of capacity from the resource that is subject to a Capacity Supply Obligation for the month. For the month associated with the greatest of these 12 values, if the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity (as applicable) is below the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month by more than the lesser of 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or 40 MW, then the following provisions shall apply:

(a) The Lead Market Participant may submit a written plan to the ISO with any necessary supporting documentation describing the measures that will be taken and demonstrating that the resource will be able to provide an amount of capacity consistent with its total Capacity Supply Obligation for the Capacity Commitment Period by the start of all months in that Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If submitted, such a plan must be received by the ISO no later than 10 Business Days after the ISO has notified the Lead Market Participant of its Summer ARA Qualified Capacity and Winter ARA Qualified Capacity for the third annual reconfiguration auction.

(b) If no such plan as described in Section III.13.4.2.1.3(a) is timely submitted to the ISO, or if such a plan is timely submitted but the ISO determines that the plan does not demonstrate that the resource will be able to provide the necessary amount of capacity by the start of all months in the Capacity

Commitment Period in which the resource has a Capacity Supply Obligation, then the ISO shall enter a demand bid at the Forward Capacity Auction Starting Price (or, in the case of a resource that cleared in the seventh Forward Capacity Auction, at \$12.11/kW-month) on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) in the third annual reconfiguration auction in an amount equal to the greatest of the 12 monthly values determined pursuant to this Section III.13.4.2.1.3.

(c) If the ISO determines that the resource is not able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, and if the resource was part of an offer composed of separate resources when it qualified to participate in the relevant Forward Capacity Auction, then before a demand bid is entered for the resource pursuant to subsection (b) above, the resource may submit monthly Capacity Supply Obligation Bilaterals, subject to the satisfaction of the requirements in Section III.13.5, to cover the deficiency for the months of the Capacity Commitment Period in which the Capacity Supply Obligation is associated with participation in an offer composed of separate resource prior to the third annual reconfiguration auction, but in no case may such a Capacity Supply Obligation Bilateral for a month be for an amount of capacity greater than the difference between the resource's Capacity Supply Obligation for the month and the resource's lowest monthly Capacity Supply Obligation during the Capacity Commitment Period.

III.13.4.2.1.4. Amount of Capacity That May Be Submitted in a Supply Offer in a Monthly Reconfiguration Auction.

A resource that has not achieved Commercial Operation by the offer and bid deadline for a monthly reconfiguration auction may not submit a supply offer for that reconfiguration auction, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a supply offer for that reconfiguration auction in an amount up to the absolute value of its Capacity Supply Obligation. The amount of capacity up to which a resource may submit a supply offer in a monthly reconfiguration auction shall be the difference (but in no case less than zero) between (i) the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity as adjusted pursuant to Section III.13.4.2, as applicable, for the auction month for the third annual reconfiguration auction for the relevant Capacity Commitment Period; and (ii) the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month. However, a resource may not submit a supply offer for a monthly reconfiguration auction if it is on an approved outage during that month.

III.13.4.2.1.5. ISO Review of Supply Offers.

Supply offers in reconfiguration auctions 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 reviews will consider the location and operating and rating limitations of resources associated with cleared supply offers to ensure reliability standards will remain satisfied if the offer is accepted. The ISO shall reject supply offers that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction. The ISO's reliability reviews will assess such offers, beginning with the marginal resource, 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. Supply offers that cannot meet the applicable reliability needs will be rejected in their entirety and the resource will not be rejected in part. Rejected resources will not be further included in clearing the reconfiguration auction and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.2.2. Demand Bids in Reconfiguration Auctions.

Submission of demand bids in reconfiguration auctions shall be governed by this Section III.13.4.2.2. All demand bids in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the amount of capacity bid in MW, and the price, in dollars per kW/month.

- (a) To submit a demand bid in a reconfiguration auction, a resource must have a Capacity Supply Obligation for the Capacity Commitment Period (or portion thereof, as applicable) associated with that reconfiguration auction. Where capacity associated with a Self-Supplied FCA Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period is offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof, a resource acquiring a Capacity Supply Obligation shall not as a result become a Self-Supplied FCA Resource.
- (b) Each demand bid submitted to the ISO for reconfiguration auction shall be no greater than the amount of the resource's capacity that is already obligated for the Capacity Commitment Period (or portion thereof, as applicable) as of the offer and bid deadline for the reconfiguration auction.
- (c) All demand bids in reconfiguration auctions 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 reviews will consider the location and operating and rating limitations of resources associated with cleared demand bids to ensure reliability standards will remain satisfied if the committed capacity is withdrawn. The ISO shall reject demand bids that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction, provided that for annual reconfiguration auctions associated with a Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall not reject a demand bid solely on the basis that acceptance of the demand bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs). For monthly reconfiguration auctions, the ISO shall obtain and consider information from the Local Control Center regarding whether the capacity associated with demand bids that would otherwise clear from resources with a Capacity Supply Obligation is needed for local system conditions. The ISO's reliability reviews will assess such bids, beginning with the marginal resource, 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. Where the applicable reliability needs cannot be met if a Demand Bid is cleared, such Demand Bids will be rejected in their entirety and the resource will not be rejected in part. Demand Bids from rejected resources will not be further included in clearing the reconfiguration auction, and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.3. ISO Participation in Reconfiguration Auctions.

The ISO shall not submit supply offers or demand bids in monthly reconfiguration auctions. The ISO shall submit supply offers and demand bids in annual reconfiguration auctions as appropriate to address year-to-year changes in the Installed Capacity Requirement (net of HQICCs), Local Sourcing Requirements and Maximum Capacity Limits for the associated Capacity Commitment Period, to procure capacity not purchased in the Forward Capacity Auction as a result of the "Inadequate Supply" rule for Forward Capacity Auctions conducted prior to June 2015, to procure any shortfall in capacity resulting from a resource's achieving Commercial Operation at a level less than that resource's Capacity Supply Obligation or other significant decreases in capacity, and to address any changes in external interface limits, as follows:

- (a) For each Capacity Commitment Period that begins on or before June 1, 2017, the ISO shall submit supply offers and demand bids in annual reconfiguration auctions as appropriate to ensure that the applicable Installed Capacity Requirement (net of HQICCs), Local Sourcing Requirements, Maximum

Capacity Limits, and external interface limits are respected. Where less capacity than needed is obligated, the ISO shall submit demand bids as appropriate to procure the additional needed capacity in each subsequent annual reconfiguration auction until the need is met. Where more capacity than needed is obligated, the ISO may in its discretion submit supply offers in subsequent annual reconfiguration auctions to release the excess capacity, but in any case the ISO shall be required to submit supply offers as appropriate in the third annual reconfiguration auction for a Capacity Commitment Period to release the excess capacity.

(b) For each Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall submit demand bids for the amount of additional capacity needed to meet the Local Sourcing Requirements and shall submit supply offers in the third annual reconfiguration auction for a Capacity Commitment Period to release capacity exceeding the Maximum Capacity Limits or external interface limits.

(c) No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall provide notice regarding whether the ISO will be submitting supply offers or demand bids in that auction.

(d) Any demand bid submitted by the ISO in an annual reconfiguration auction shall be at the Forward Capacity Auction Starting Price, except for any demand bids submitted by the ISO in annual reconfiguration auctions associated with the seventh Capacity Commitment Period, which shall be at \$12.11/kW-month.

(e) Any supply offer submitted by the ISO in an annual reconfiguration auction shall be in the form of a supply curve having the following characteristics:

(i) at prices equal to or greater than 0.75 times the Capacity Clearing Price, as adjusted pursuant to Section III.13.2.7.3(b), from the Forward Capacity Auction for the Capacity Commitment Period covered by the annual reconfiguration auction, the ISO shall offer the full amount of the surplus;

(ii) at prices between 0.75 times such Capacity Clearing Price and 0.25 times such Capacity Clearing Price, the amount of the surplus offered by the ISO shall decrease linearly (for example, at 0.5 times such Capacity Clearing Price, the ISO shall offer half of the amount of the surplus); and

(iii) At prices equal to or below 0.25 times such Capacity Clearing Price, the ISO shall offer no capacity.

(f) For purposes of this Section III.13.4.3, the Forward Capacity Auction Starting Price shall be the Forward Capacity Auction Starting Price associated with the Forward Capacity Auction for the same Capacity Commitment Period addressed by the reconfiguration auction, as determined pursuant to Section III.13.2.4.

(g) Supply offers and demand bids submitted by the ISO in annual reconfiguration auctions are not subject to the requirements and limitations described in Section III.13.4.2.

(h) Supply offers and demand bids submitted by the ISO in annual reconfiguration auctions are not associated with a resource.

III.13.4.4. Clearing Offers and Bids in Reconfiguration Auctions.

All supply offers and demand bids may be cleared in whole or in part in all reconfiguration auctions. If after clearing, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.4.5. Annual Reconfiguration Auctions.

Except as provided below, after the Forward Capacity Auction for a Capacity Commitment Period, and before the start of that Capacity Commitment Period, the ISO shall conduct three annual reconfiguration auctions for capacity commitments covering the whole of that Capacity Commitment Period. For each annual reconfiguration auction, the capacity demand curves, New England Control Area and Capacity Zone capacity requirements and external interface limits, as updated pursuant to Section III.12, shall be modeled in the auction consistent with the Forward Capacity Auction for the associated Capacity Commitment Period. For purposes of the annual reconfiguration auctions, the Forward Capacity Auction Starting Price used to define the System-Wide Capacity Demand Curve shall be the Forward Capacity Auction Starting Price associated with the Forward Capacity Auction for the same Capacity Commitment Period addressed by the reconfiguration auction.

III.13.4.5.1. Timing of Annual Reconfiguration Auctions.

Except for the first five Capacity Commitment Periods, the first annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of June that is approximately 24 months before the start of the Capacity Commitment Period. The second annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of August that is approximately 10 months before the start of the Capacity Commitment Period. The third annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of March that is approximately 3 months before the start of the Capacity Commitment Period. There shall be no first annual reconfiguration auction for the first five Capacity Commitment Periods. The table below illustrates the annual reconfiguration auction timing provisions stated above, providing the schedule of annual reconfiguration auctions for the first eight Capacity Commitment Periods.

First Annual Reconfiguration Auction	Second Annual Reconfiguration	Third Annual Reconfiguration	Capacity Commitment Period Begins
N/A	May 2009	March 2010	June 1, 2010
N/A	May 2010	March 2011	June 1, 2011
N/A	May 2011	March 2012	June 1, 2012
N/A	May 2012	March 2013	June 1, 2013
N/A	August 2013	March 2014	June 1, 2014
June 2013	August 2014	March 2015	June 1, 2015
June 2014	August 2015	March 2016	June 1, 2016
June 2015	August 2016	March 2017	June 1, 2017

III.13.4.5.2. Acceleration of Annual Reconfiguration Auction.

If the difference between the forecasted Installed Capacity Requirement (net of HQICCs) for a Capacity Commitment Period and the amount of capacity obligated for that Capacity Commitment Period is sufficiently large, then the ISO may, upon reasonable notice to Market Participants, conduct an annual reconfiguration auction as much as six months earlier than its normally-scheduled time.

III.13.4.6. [Reserved.]

III.13.4.7. Monthly Reconfiguration Auctions.

Prior to each month in the Capacity Commitment Period, the ISO shall conduct a monthly reconfiguration auction for whole-month capacity commitments during that month. For each monthly reconfiguration auction, the Local Sourcing Requirement and Maximum Capacity Limit applicable for each Capacity Zone and external interface limits, as updated pursuant to Section III.12, shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in monthly reconfiguration auctions.

III.13.4.8. Adjustment to Capacity Supply Obligations.

For each supply offer that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be increased by the amount of capacity that clears. For each demand bid that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be decreased by the amount of capacity that clears.

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 Capacity Performance Bilaterals in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.

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. A seasonal Capacity Supply Obligation Bilateral can be entered into only during the Capacity Supply Obligation Bilateral window associated with the third Annual Reconfiguration Auction, must be contained within a single Capacity Commitment Period, and must contain all the months in the summer or winter season identified by the Capacity Transferring Resource and only those months. For the purposes of this Section III.13.5, the summer season of a Demand Capacity Resource is all of the months from June through November and April through May of the same Capacity Commitment Period and the winter season of a Demand Capacity Resource is all of the months from December through March; for all other resource types, the summer season is all of the months from June through September and the winter season is all of the months October through May. Prior to January 1, 2017, a seasonal Capacity Supply Obligation Bilateral can only be entered into if the Capacity Transferring Resource has been identified by the ISO as a resource having a significant decrease pursuant to Section III.13.4.2.1.3.

(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 month, season or Capacity Commitment 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 month, season or Capacity Commitment 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. If the season of the Capacity Transferring Resource is not aligned with the season of the Capacity Acquiring Resource and the seasonal Capacity Supply Obligation Bilateral spans more than one season of the Capacity Acquiring Resource, the lowest monthly amount of unobligated Qualified Capacity of the Capacity Acquiring Resource will be used.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource's unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.

(d) [Reserved.]

(e) [Reserved.]

(f) [Reserved.]

(g) [Reserved.]

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant 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 and Prior Notification to the ISO.

The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

A Lead Market Participant or Project Sponsor seeking to submit a monthly Capacity Supply Obligation Bilateral pursuant to Section III.13.3.4 (covering where resource will not achieve commercial operation by start of Capacity Commitment Period) or a monthly Capacity Supply Obligation bilateral pursuant to Section III.13.4.2.1.3(c) (significant decrease of offers composed of separate resources) must notify the ISO in writing of its intention to do so no later than four Business Days prior to the start of the relevant annual Capacity Supply Obligation Bilateral submittal window.

Prior to January 1, 2017, a Lead Market Participant or Project Sponsor seeking to submit a seasonal Capacity Supply Obligation Bilateral must notify the ISO of its intention to do so no later than four Business Days prior to the start of the Capacity Supply Obligation Bilateral window associated with the third annual reconfiguration auction.

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 and seasonal 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 and seasonal 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 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. Capacity Performance Bilaterals.

A resource's Capacity Performance Score during a Capacity Scarcity Condition may be adjusted by entering into a Capacity Performance Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. Eligibility.

If a resource has a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five-minute interval so long as both resources were subject to the same Capacity Scarcity Condition.

III.13.5.3.2. Submission of Capacity Performance Bilaterals.

The Lead Market Participant for a resource having a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition may submit a Capacity Performance Bilateral to the ISO assigning all or a portion of its Capacity Performance Score for that interval to another resource, subject to the eligibility requirements specified in Section III.13.5.3.1. The Capacity Performance Bilateral must be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score.

III.13.5.3.2.1. Timing.

A Capacity Performance Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the month associated with the Capacity Performance Bilateral, a Capacity Performance Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Capacity Performance Bilateral may be revised by the parties to the transaction throughout the resettlement process).

III.13.5.3.2.2. Application.

The submission of a Capacity Performance Bilateral to the ISO shall include the following: (i) the resource identification number for the resource transferring its Capacity Performance Score; (ii) the resource identification number for the resource receiving the Capacity Performance Score; (iii) the MW amount of Capacity Performance Score being transferred; (iv) the specific five-minute interval or intervals for which the Capacity Performance Bilateral applies.

III.13.5.3.2.3. ISO Review.

The ISO shall review the information provided in submission of the Capacity Performance Bilateral, and shall reject the Capacity Performance Bilateral if any of the provisions of this Section III.13.5.3 are not met.

III.13.5.3.3. Effect of Capacity Performance Bilateral.

A Capacity Performance Bilateral does not affect in any way either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Capacity Performance Bilateral is to modify the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Conditions subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments as described in Section III.13.7.2.

III.13.6. 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 with Capacity Supply Obligations.

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.

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 with Capacity Supply Obligations.

III.13.6.1.2.1. Energy Market Offer Requirements.

The Real-Time Energy Market offer requirements in this Section III.13.6.1.2.1 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

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 for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.

(a) 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.

(b) 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.

(c) 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.

III.13.6.1.2.2. Additional Requirements for Certain Import Capacity Resources.

The additional requirements for Import Capacity Resources in this Section III.13.6.1.2.2 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

- (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.13.6.1.2.3. Additional Requirements for Import Capacity Resources at External Interfaces with Enhanced Scheduling.

Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented are subject to the following additional requirements unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1. 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 the requirements in this Section III.13.6.1.2.3 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.

(a) The resource must comply with all information submittal requirements for Day-Ahead Energy Market Coordinated External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals.

(b) Where the Import Capacity Resource is physically located in a Control Area with which the New England Control Area has implemented the enhanced scheduling procedures in Section III.1.10.7.A, the resource must comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the native Control Area.

(c) The resource must notify the ISO of all outages impacting the Capacity Supply Obligation of the resource in accordance with the outage notification requirements in ISO New England Operating Procedures.

(d) At the time of submittal, each Coordinated External Transaction submitted to the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

III.13.6.1.3. Intermittent Power Resources with Capacity Supply Obligations.

III.13.6.1.3.1. Energy Market Offer Requirements.

Market Participants may submit offers into the Day-Ahead Energy Market for Intermittent Power Resources with a Capacity Supply Obligation. Market Participants are required to submit offers for Intermittent Power Resources with a Capacity Supply Obligation for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day-Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

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 Capacity Resources with Capacity Supply Obligations.

III.13.6.1.5.1. Energy Market Offer Requirements.

~~(a) Seasonal Peak Demand Resources and On-Peak Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Markets.~~

A Market Participant with an Active 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 Active 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 Active 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) Seasonal Peak Demand Resources and On-Peak Demand Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market, 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 an Active Demand Response Capacity Resource must reflect the then-known operating characteristics of the resource. Consistent with Section III.1.10.9(d), Demand Response Resources must re-declare to the ISO any changes to ~~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.

III.13.6.1.5.3. Additional Requirements for Demand Capacity Resources.

(a) A Market Participant may not associate an Asset with a non-commercial Demand Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Demand Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) If a Demand Capacity Resource has summer Qualified Capacity, a summer Seasonal DR Audit value or summer Passive DR Audit value may be used to verify the commercial capacity of the resource.

A winter Seasonal DR Audit value or winter Passive DR Audit value may only be used to verify the winter commercial capacity of the resource.

(c) For Active Demand Capacity Resources, a summer Seasonal DR Audit value shall be established for use from April 1 through November 30 and a winter Seasonal DR Audit value shall be established for use from December 1 through March 31. The summer or winter Seasonal DR Audit value of an Active Demand Capacity Resource is equal to the sum of the like-season Seasonal DR Audit values of its constituent Demand Response Resources as determined pursuant to Section III.1.5.1.3.1. The Seasonal DR Audit value of an Active Demand Capacity Resource shall automatically update whenever a new Seasonal DR Audit value is approved for a constituent Demand Response Resource or with changes to the makeup of the constituent Demand Response Resources.

(d) On-Peak Demand Resources and Seasonal Peak Demand Resources shall in addition: (i) comply with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals; and (ii) comply with the auditing and rating requirements as detailed in Sections III.13.6.1.5.4 and III.13.6.1.5.5 and the ISO New England Manuals.

(e) Active Demand ~~Response~~-Capacity Resources shall in addition: (i) ~~having a Capacity Supply Obligation comply with~~ are subject to the following additional requirements: the measurement and verification requirements and the

(a) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, ~~and with~~

(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; ~~and~~ (ii) comply with the auditing and rating requirements as detailed in Section III.13.6.1.5.5 and the ISO New England Manuals.

III.13.6.1.5.4. On-Peak Demand Resource and Seasonal Peak Demand Resource ~~Response~~ Auditing Requirements.

~~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) A summer Passive DR Audit and a winter Passive DR Audit must be performed by each On-Peak Demand Resource and Seasonal Peak Demand Resource in every Capacity Commitment Period during which the On-Peak Demand Resource or Seasonal Peak Demand Resource has an annual or monthly Capacity Supply Obligation.~~

~~(b) Summer Passive DR Audits shall be performed during the summer Passive DR Auditing Period (June 1 through August 31). Winter Passive DR Audits shall be performed during the winter Passive DR Auditing Period (December 1 through January 31).~~

~~(c) Passive DR Audits are performed following the request of the Market Participant. Audits will be performed within 20 Business Days of the date requested by the Market Participant.~~

~~(d) Audits of an On-Peak Demand Resource will be are conducted by simultaneously evaluating the performance-Average Hourly Output or Average Hourly Load Reduction of each demand-aAsset associated with the On-Peak Demand Resource during the Demand Resource On-Peak Hours. that is mapped to that Demand Resource.~~

~~(e) Audits of a Seasonal Peak Demand Resource are conducted by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the Seasonal Peak Demand~~

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Resource during the Demand Resource Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in a month during the Passive DR Auditing Period, performance during Demand Resource On-Peak Hours in that month may be used.

(f) The Passive DR Audit value of an On-Peak Demand Resource or Seasonal Peak Demand Resource is valid beginning with the month for which performance data is submitted and remains valid until the earlier of: (i) the next like-season Passive DR Audit or (ii) the end of the next like-season Passive DR Auditing Period.

(g) At the request of a Market Participant, an audit may be performed outside of the summer Passive DR Auditing Period or winter Passive DR Auditing Period. Such an audit shall not satisfy the Passive DR Audit requirement, however the results of such an audit conducted during the months of September, October, November, April, or May shall be used in the calculation of the Demand Capacity Resource's summer Passive DR Audit value and the results of such an audit conducted during the months of February or March shall be used in the calculation of the Demand Capacity Resource's winter Passive DR Audit value.

(h) If by August 1 for the summer Passive DR Auditing Period or by January 1 for the winter Passive DR Auditing Period a Market Participant has not requested a Passive DR Audit, the Market Participant shall be deemed to have requested a Passive DR Audit on those respective dates. An On-Peak Demand Resource or Seasonal Peak Demand Resource that does not successfully perform a Passive DR Audit for a Passive DR Auditing Period shall have its audit results set to zero.

(e) _____

(b) [Reserved.]

(e) 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.

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~~(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) — [Reserved.]~~

~~(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, 2018, the audit results for Demand Response Resources comprised of Demand Response Assets that were associated with an active Demand 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, 2018, 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,

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~~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. — [Reserved.]**~~

~~**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 Capacity Scarcity Condition 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.8B 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 an event occurs before a Demand Response Resource has established an Audited Demand Reduction value and the resource was not dispatched during the 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;~~

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~~(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.~~

~~**III.13.6.1.5.5. — Additional Demand Capacity Resource Audits.**~~

~~The ISO may perform additional audits for a Demand Capacity Resource to establish or verify the capability of the Demand Capacity Resource and its underlying audit results or Audited Demand Reduction and the performance of the installed measures of the demand asset or Demand Response Assets and measures. 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~~ Assets and measures to verify that the reported Assets and measures have been installed and are operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.

(b) Level 2 Audit: the ISO ~~shall~~ will establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of ~~measures in the demand assets and measures of 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 Capacity Resource is less than or greater than its ~~Demand Reduction Value or Audited Demand Reduction in the same period most recent like-season Passive DR Audit value or Seasonal DR Audit value~~, then ~~the Demand Reduction Value or Audited Demand Reduction the Demand Capacity Resource's audit value~~ shall be adjusted ~~accordingly 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) [Reserved.] (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).~~

~~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.~~

~~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.~~

~~(b) — 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; and~~

~~(c) — For determination regarding termination under Section III.13.3.4(c).~~

~~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.~~

III.13.6.1.6. DNE Dispatchable Generator.

III.13.6.1.6.1. Energy Market Offer Requirements.

Beginning on June 1, 2019, Market Participants with DNE Dispatchable Generators with a Capacity Supply Obligation must submit offers into the Day-Ahead Energy Market for the full amount of the resource's expected hourly physical capability as determined by the Market Participant. Market Participants with DNE Dispatchable Generators having a Capacity Supply Obligation must submit offers for the Real-Time Energy Market consistent with the characteristics of the resource. For purposes of calculating Real-Time NCPC Charges, DNE Dispatchable Generators shall have a generation deviation of zero.

III.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 without a Capacity Supply Obligation.

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 may submit an offer into the Real-Time Energy Market. If any portion of the offered energy clears in the Real-Time Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Real-Time Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow ISO dispatch instructions. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.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 without a Capacity Supply Obligation.**

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 Capacity Resources without a Capacity Supply Obligation.

III.13.6.2.5.1. Energy Market Offer Requirements.

~~Seasonal Peak and On-Peak Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.~~ A Market Participant with a Demand Response Resource associated with an Active 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.

~~Seasonal Peak Demand Resources and On-Peak Demand Resources may not submit Demand Reduction Offers 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 an Active 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 an Active 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 Section III.13.6.1.5.3(a) and (b) and with the auditing and rating requirements ~~as detailed-described~~ in Section III.13.6.1.5.45 and the ISO New England Manuals; and

(b) for Active Demand Capacity Resources, complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) for Active Demand Capacity Resources, complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Active 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 Capacity Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7.

III.13.6.4. ISO Requests for Energy.

The ISO may request that an Active Demand ~~Response~~ Capacity Resource or a 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. 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.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1, as adjusted to account for peak energy rents as described in Section III.13.7.1.2.

III.13.7.1.1. Monthly Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period based on the following amounts:

(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 of a New Generating Capacity Resource that has cleared in the Forward Capacity Auction and 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, 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 by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated

with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to 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.13.7.1.2 Peak Energy Rents.

Capacity Base Payments to resources with Capacity Supply Obligations, except for (1) On-Peak Demand Resources, (2) Seasonal Peak Demand Resources, and (3) New Generating Capacity Resources that have cleared in the Forward Capacity Auction and have completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service are not able to achieve Commercial Operation, 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. Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied.

III.13.7.1.2.1 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:

$$\text{Hourly PER}(\$/\text{kW}) = [\text{LMP} - \text{Strike Price}] * [\text{Scaling Factor}] * [\text{Availability Factor}]$$

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 Capacity 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.13.7.1.2.2. Monthly PER Application.

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 the Average Monthly PER multiplied by the resource's Capacity Supply Obligation for the Obligation Month (less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource); provided, however, that in no case shall a resource's PER deduction for an Obligation Month be less than zero or greater than the product of the resource's Capacity Supply Obligation and the relevant Forward Capacity Auction Capacity Clearing Price.

III.13.7.1.3. Export Capacity.

If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

Charge Amount to Resource Exporting = [Capacity Clearing Price_{location of the interface} - Capacity Clearing Price_{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_{location of the interface} - Capacity Clearing Price_{location of the resource}] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.5.1.

III.13.7.1.4. [Reserved.]

III.13.7.2 Capacity Performance Payments.

III.13.7.2.1 Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement; (ii) the system-wide Ten-Minute Non-Spinning Reserve requirement; or (iii) the local Thirty-Minute Operating Reserve requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Real-Time Reserve Designation (including any regulation capability available but not used for energy) during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Real-Time Designation (including any regulation capability available but not used for energy) during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered (but not less than zero) during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource,

then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the resource's Average Hourly Output or Average Hourly Load Reduction, where the MWhs of reduction, other than MWhs associated with Net Supply, are multiplied by 1.08 increased by average avoided peak transmission and distribution losses.

(d) A Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the resource's Average Hourly Output or Average Hourly Load Reduction, where the MWhs of reduction, other than MWhs associated with Net Supply, are multiplied by 1.08 increased by average avoided peak transmission and distribution losses.

(e) [Reserved.]

(f) An Active Demand Response-Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Real-Time demand reduction ~~for of~~ each associated Demand Response ~~Asset Resource (in accordance with Section 7.1 of Appendix E2 to Market Rule 1) associated with the Demand Response Capacity Resource (where the MWhs of reduction, other than the MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses multiplied by 1.08, plus the sum of the Net Supply from each Net Supply Generator Asset associated with the Demand Response Capacity Resource);~~ plus the resource's Real-Time Reserve Designation (adjusted as described in III.9.6.5(h)).

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

$$(\text{Load} + \text{Reserve Requirement}) / \text{Total Capacity Supply Obligation}$$

(a) If the Capacity Scarcity Condition is a result of a violation of the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning Reserve requirement during the interval plus the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval.

(b) If the Capacity Scarcity Condition is a result of a violation of the system-wide Ten-Minute Non-Spinning Reserve requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning Reserve requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval.

(c) If the Capacity Scarcity Condition is a result of a violation of the local Thirty-Minute Operating Reserves requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero).

Reserve Requirement = the local Thirty-Minute Operating Reserve requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the local Thirty-Minute Operating Reserves requirement and either the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement or the system-wide Ten-Minute Non-Spinning Reserve requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(c).

(ii) In any Capacity Zone subject to both the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement and the system-wide Ten-Minute Non-Spinning Reserve requirement, but not to Reserve Constraint Penalty Factor pricing associated with the local Thirty-Minute Operating Reserves requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval minus the product of the resource's Capacity Supply Obligation and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, if the Capacity Scarcity Condition occurs in an interval outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided and Capacity Supply Obligation associated with any On-Peak Demand Resource or Seasonal Peak Demand Resource comprised exclusively of Energy Efficiency Demand Response Assets-measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be \$2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be \$3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be \$5455/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

III.13.7.3.1 Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.12.2.75, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the

product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month).

III.13.7.3.2 Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

$$\text{MaxCSO} \times [3 \text{ months} \times (\text{FCAcp} - \text{FCAsp}) - (12 \text{ months} \times \text{FCAcp})]$$

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments.

For each type of Capacity Scarcity Condition as described in Section III.13.7.2.1 and for each Capacity Zone, the ISO shall allocate deficient or excess Capacity Performance Payments as described in

subsections (a) and (b) below. Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.

(a) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(a).

(b) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.13.7.4(b)

III.13.7.5. 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 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), less PER adjustments for resources in the zone as defined in Section III.13.7.1.2, and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load

serving entity 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.13.7.5.1. 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; load that is modeled as an Asset Related Demand or discrete load asset and is exclusively related to an Alternative Technology Regulation Resource following AGC dispatch instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A 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 load serving entity's Capacity Requirement A Demand Resource's Demand Reduction Value~~ will not be reconstituted ~~into the~~ to include the load demand reduction of a the Demand Capacity Resource or Demand Response Resource for the purpose of determining the Capacity Requirement for the load associated with the Demand Resource.

III.13.7.5.1.1. 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.13.7.5.1.2. 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.13.7.5.1.3. 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.13.7.5.2. 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.13.7.5.3.

III.13.7.5.3. Capacity Transfer Rights.

III.13.7.5.3.1. 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.13.7.5.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER.

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.13.7.5.3.2(c), III.13.7.5.3.4, and III.13.7.5.3.6 shall be calculated as the product of: (i) the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to “Inadequate Supply” or “Insufficient Competition”)

that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015 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)), or, if applicable, minus the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to “Inadequate Supply” or “Insufficient Competition”) that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015 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.13.7.5.3.2.

III.13.7.5.3.2. 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.13.7.5.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

- (a) **Connecticut Import Interface.** The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

- (b) **NEMA/Boston Import Interface.** Except as provided in Section III.13.7.5.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

- (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.13.7.5.3.6. 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.13.7.5.3.3. 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.13.7.5.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.5.3.4. 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.13.7.5.3.2.

(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.13.7.5.3.2.

III.13.7.5.3.5. [Reserved.]

III.13.7.5.3.6. 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	Winter
									(MW)	(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.13.7.5.4. 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.

III.13.8. Reporting and Price Finality

III.13.8.1. Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto.

(a) For each Forward Capacity Auction, no later than 20 Business Days after the issuance of retirement determination notifications described in Section III.13.1.2.4(a), the ISO shall make a filing with the Commission pursuant to Section 205 of the Federal Power Act describing the Permanent De-List Bids and Retirement De-List Bids. The ISO will file the following information confidentially: the determinations made by the Internal Market Monitor with respect to each Permanent De-List Bid and Retirement De-List Bid, and supporting documentation for each such determination. The confidential filing shall indicate those resources that will permanently de-list or retire prior to the Forward Capacity Auction and those Permanent De-List Bids and Retirement De-List Bids for which a Lead Market Participant has made an election pursuant to Section III.13.1.2.4.1.

(b) The Forward Capacity Auction shall be conducted using the determinations as approved by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

(c) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), and (viii) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), and (viii) shall be published by the ISO no later than 15 days after the Forward Capacity Auction), with the exception of de-list bid price information, which shall remain confidential):

- (i) which Capacity Zones shall be modeled in the Forward Capacity Auction;
- (ii) the transmission interface limits as determined pursuant to Section III.12.5;

(iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

(iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;

(v) [reserved];

(vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;

(vii) the Internal Market Monitor's determinations regarding each requested offer price from a new resource submitted pursuant to Section III.13.1.1.2.2.3 or Section III.13.1.4.[1.1.2.8](#), including information regarding each of the elements considered in the Internal Market Monitor's determination of expected net revenues (other than revenues from ISO-administered markets) and whether that element was included or excluded in the determination of whether the offer is consistent with the resource's long run average costs net of expected net revenues other than capacity revenues;

(viii) the Internal Market Monitor's determinations regarding offers or Static De-List Bids, Export Bids, and Administrative De-List Bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the Internal Market Monitor-determined prices established for any Static De-List Bids, Export Bids, and Administrative De-List Bids as described in Section III.13.1.2.3.2 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 filing shall identify to the extent possible the components of the bid which were accepted as justified, and shall also identify to the extent possible the components of the bid which were not justified and which resulted in the Internal Market Monitor establishing an Internal Market Monitor-determined price for the bid;

(ix) which existing resources are qualified to participate in the Forward Capacity Auction (this information will include resource type, capacity zone, and qualified MW); and

(x) aggregate MW from new resources qualified to participate in the Forward Capacity Auction and aggregate de-list bid amounts.

(d) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(c) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4(b) and III.13.1.3.5.7 must be filed with the Commission no later than 15 days after the ISO's submission of the informational filing. If the Commission does not issue an order within 75 days after the ISO's submission of the informational filing that directs otherwise, the determinations contained in the informational filing shall be used in conducting the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within 75 days after the ISO's submission of the informational filing, the Commission does issue an order modifying one or more of the ISO's determinations, then the Forward Capacity Auction shall be conducted no earlier than 15 days following that order using the determinations as modified by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Facility, as defined in Schedule 22 or Schedule 25 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity Auction subject to a Long Lead Time Facility with the higher queue priority. The filing shall also

enumerate bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.

(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO's filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.

(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.

III.14 Regulation Market.

For purposes of this Section III.14, the settlement interval is every five minutes. If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.14.1 Regulation Market System Requirements.

The Regulation Capacity Requirement and Regulation Service Requirement are determined based on historical control performance and compliance with NERC and NPCC control standards. The Regulation Capacity Requirement and Regulation Service Requirement will be published on the ISO's website.

During abnormal system conditions, the ISO may deviate from the Regulation Capacity Requirement or Regulation Service Requirement to maintain system reliability.

III.14.2 Regulation Market Eligibility.

To be eligible to provide Regulation, a Resource must satisfy the following conditions:

- (a) Physical Parameters.
 - (i) Automatic Response Rate.
 - (1) The minimum Automatic Response Rate is 1 MW/minute.
 - (ii) Regulation Capacity.
 - (1) The minimum Regulation Capacity of a generating unit will be determined based on unit size and operating characteristics and must be greater than or equal to: (a) 5 megawatts, and; (b) two times the generating unit's AGC SetPoint Deadband plus one.
 - (2) The minimum Regulation Capacity of a Resource that is not a generating unit is no less than one megawatt after aggregation.
- (b) Regulation Technical Requirements.

A Resource providing Regulation must:

 - (i) be located within the New England Control Area.
 - (ii) meet the technical requirements specified in ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands and ISO New England Operating Procedure No. 18, Metering and Telemetry Criteria.

(iii) be capable of receiving and following AGC SetPoints sent electronically at four-second intervals.

(iv) have a demonstrated capability to reliably follow Dispatch Instructions, consistent with normal operating characteristics and physical offer parameters, including Regulation Capacity and Automatic Response Rate. Resources without an operational history of providing Regulation must establish and demonstrate this capability as follows:

(1) Demand Response Regulation Resources, Dispatchable Asset Related Demand, Alternative Technology Regulation Resources and any Resource with less than one-hour sustainability must participate in the Regulation test environment specified in Section III.14.9.

(2) All Resources must satisfy a minimum responsiveness test that demonstrates that a Resource can follow AGC SetPoints.

(c) Aggregation.

Non-generation sub-resources less than one megawatt in size may be aggregated into a single Resource to meet the Regulation Market eligibility requirements specified in Section III.14.2.

A single AGC SetPoint will be sent every AGC cycle to the aggregated Resource. A Market Participant with an aggregated Resource is responsible for management and control of the individual, aggregated sub-resources to ensure an accurate aggregate response to the AGC SetPoint. The sub-resources may be geographically dispersed, provided:

(i) all of the sub-resources are located within the New England Control Area

(ii) the sub-resources are metered and recorded in a manner that allows real-time performance to be measured against Dispatch Instructions and provides for the retention of the recorded information for purposes of verification, accounting for any performance offsets from other loads, generation or devices under the direct or indirect control of the aggregator as specified in ISO New England Operating Procedure No. 18, Metering and Telemetry Criteria.

(iii) communications and metering are installed and tested for each sub-resource in accordance with ISO New England Operating Procedure No. 18, Metering and Telemetry Criteria and ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands.

III.14.3 Regulation Market Offers.

(a) A Market Participant providing Regulation must submit a Supply Offer. The Supply Offer shall remain effective until cancelled or replaced by the Market Participant. The Supply Offer must specify the following offer parameters:

(i) Regulation unit status (available/unavailable)

Regulation unit status for each hour in an Operating Day must be submitted daily prior to the close of the Re-Offer Period. After initial submission, unit status may be modified at any time.

(ii) Regulation High Limit

For generating units, the Regulation High Limit must be less than or equal to a generating unit's Economic Maximum Limit. For Dispatchable Asset Related Demand, the Regulation High Limit must be greater than or equal to a Dispatchable Asset Related Demand's Minimum Consumption Limit.

(iii) Regulation Low Limit

For generating units, the Regulation Low Limit must be greater than or equal to a generating unit's Economic Minimum Limit. For Dispatchable Asset Related Demand, the Regulation Low Limit must be less than or equal to a Dispatchable Asset Related Demand's Maximum Consumption Limit.

(iv) Automatic Response Rate (MW/minute)

(v) Regulation Capacity Offer (\$/MW)

The Regulation Capacity Offer price must be greater than or equal to \$0/MW and may not exceed \$100/MW. A Market Participant may include estimated inter-temporal opportunity costs in its Regulation Capacity Offer price.

(vi) Regulation Service Offer (\$/MW of instructed movement)

The Regulation Service Offer price must be greater than or equal to \$0/MW of instructed movement and may not exceed \$10/MW of instructed movement.

(b) Additional Constraints on Offer Parameters.

(i) Regulation offer parameters that exceed recent historical performance for Regulation Capacity or Automatic Response Rate will be constrained to reflect values consistent with the demonstrated performance of the Resource. The Resource of a Market Participant that submits offer parameters inconsistent with demonstrated performance will be disqualified from selection to provide Regulation until the submitted parameters are modified to be consistent with demonstrated performance.

(ii) A Resource that is dispatchable in the Real-Time Energy Market and providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided as follows: the upper limit of the Resource's energy dispatch range will be reduced by the amount of Regulation Capacity, and the lower limit of the Resource's energy dispatch range will be increased by the amount of Regulation Capacity.

(c) Sustainability.

Regulation Capacity offers for Resources with less than one-hour sustainability will be evaluated in the selection process using a capacity value adjusted to reflect historical performance when dispatched at the non-adjusted value. The adjusted value will account for the Resource's demonstrated ability to follow the AGC dispatch signal over an hour at the offered Regulation Capacity level. The percentage adjustment will be reevaluated periodically to account for changes in the performance of the Resource. Resources with no historical performance record will be evaluated pursuant to the regulation resource test environment specified in Section III.14.9.

Adjusted Regulation Capacity will be used for the purpose of selecting Resources to meet the Regulation Capacity Requirement and for determining Regulation Capacity compensation.

Resources will be dispatched for Regulation in accordance with the unadjusted Regulation Capacity offer parameters.

For a storage-based resource, sustainability is measured based on full rate of charge/discharge starting from a half-full status.

III.14.4 Regulation Market Administration.

A Market Participant may modify Regulation offer parameters at any time, however the offer parameters in place at the start of a settlement interval will remain in effect through the end of the settlement interval.

The most recent offer parameters will be used when new Resources are selected for a new settlement interval.

III.14.5 Regulation Market Resource Selection.

Resources are selected to provide Regulation from eligible and available Resources to meet the Regulation Capacity Requirement and Regulation Service Requirement at the least-cost based on Regulation Capacity Offers, Regulation Service Offers, estimated energy opportunity costs, impacts on system production costs, and operational requirements related to reliability, including a minimum aggregated response rate and minimizing short-term changes in the assignment of Resources to provide Regulation. For the purposes of least-cost Resource selection, the following penalty factors are used for any violation of the Regulation requirements constraint:

- (1)(a) when the Energy Component of the Real-Time Locational Marginal Price at the reference point is at least \$100/MW the penalty factor is \$100/MW plus the Energy Component of the Real-Time Locational Marginal Price at the reference point for each megawatt of Regulation Capacity shortfall, and
 - (b) when the Energy Component of the Real-Time Locational Marginal Price at the reference point is less than \$100/MW the penalty factor is the maximum of either zero or \$100 plus the Energy Component of the Real-Time Locational Marginal Price at the reference point for each megawatt of Regulation Capacity shortfall and:
- (2) \$10/MW for each megawatt of Regulation Service shortfall. In addition, selection will consider opportunity cost sensitivities associated with large changes in the estimated opportunity cost of a Resource due to the shape of the Resource's Supply Offer price curve.

An eligible Resource may be omitted from providing Regulation due to operational restrictions, including, but not limited to, binding transmission constraints, planned shutdown prior to the end of the settlement interval, or known or anticipated system operating conditions.

The ISO may deviate from the market-based Resource selections to maintain system reliability.

If one or more Resources providing Regulation become unavailable, a new selection process may be conducted to obtain the Resources needed to fulfill the Regulation Capacity Requirement and the Regulation Service Requirement and new clearing prices determined pursuant to Section III.14.8(a).

In the event one or more Resources have equivalent least-cost characteristics in the selection process, the Resource with the larger Regulation Capacity value will be selected or, if the Regulation Capacity value is also equal, the Resource with the earliest Supply Offer submission time will be selected.

III.14.6 Delivery of Regulation Market Products.

Resources selected for Regulation are dispatched to reduce the New England Control Area's area control error as needed to ensure reliability and compliance with NERC and NPCC control standards.

Resources that are generating units are dispatched based on relative response rates using multi-valued AGC SetPoints with AGC SetPoint Deadbands. Resources that are not generating units may be dispatched using one of the following methods:

- (a) an energy-neutral trinary dispatch that calculates AGC SetPoints equal to one of the following three values: Regulation High Limit, Regulation Low Limit, and a midpoint between the Regulation High Limit and the Regulation Low Limit;
- (b) a relative response rate dispatch using multi-valued AGC SetPoints with AGC SetPoint Deadbands, or;
- (c) an energy-neutral relative response rate dispatch using multi-valued AGC SetPoints with AGC SetPoint Deadbands.

A Market Participant may change the dispatch method for a non-generating unit. Dispatch methodology may be changed to be effective at the start of every calendar quarter. Requests to change the dispatch method of a non-generating resource must be received no later than 30 Business Days before the requested effective date of the change. Dispatch will be coordinated with the objective of achieving consistent and non-discriminatory treatment of Resources providing similar offer parameters.

AGC SetPoints will be established to cost-effectively meet reliability criteria based on the current area control error, the Automatic Response Rate and offer parameters of the selected Resources, as well as the current and predicted state of the system.

III.14.7 Performance Monitoring.

The performance of a Resource providing Regulation will be monitored in Real-Time. For each settlement interval, a Resource is considered to be non-performing if, after a grace period, the Resource is not responding to AGC SetPoints at a rate at least equal to a percentage of its Automatic Response Rate or outside a tolerance band around the AGC SetPoint that is equal to a percentage of the Regulation Capacity of the Resource. The grace period will be between two and four minutes. The percentage of the

Automatic Response Rate will be between 80 and 95 percent. The percentage of the Regulation Capacity of the Resource will be between 5 and 15 percent. The specific values will be published on the ISO's website.

A Resource that changes its direction of movement in a manner inconsistent with the AGC SetPoint is considered non-performing for the remainder of the settlement interval.

Compensation adjustments for non-performing Resources are addressed in Section III.14.8(b)(iv).

III.14.8 Regulation Market Settlement and Compensation.

(a) Calculation of Regulation Clearing Prices.

(i) Regulation Service clearing prices.

The Regulation Service clearing price is set equal to the highest Regulation Service Offer of the Resources selected to provide Regulation pursuant to Section III.14.5.

(ii) Regulation Capacity clearing prices.

The Regulation Capacity clearing price is set such that total compensation from the Regulation Service clearing price and the Regulation Capacity clearing price will, based on a uniform clearing price applied to all selected Resources, ensure recovery of as-bid costs for Regulation Capacity, estimated Regulation Service, estimated energy opportunity costs, and the Resource-specific incremental cost savings payment determined for each Resource for the planned duration of the settlement interval.

The incremental cost savings provided by each Resource is assessed by determining the least-cost selection of Resources as specified in Section III.14.5 both with and without the particular Resource. The incremental cost savings for the settlement interval is the estimated total cost of Regulation without the Resource minus the estimated total cost of Regulation with the Resource, including the application of penalty factors to any violation of the Regulation requirements constraint.

(b) Compensation to Regulation Providers.

(i) A Market Participant with a Resource that is selected to provide Regulation and that complies with the dispatch and performance requirements in Section III.14 shall receive:

(1) A capacity payment equal to the amount of Regulation Capacity selected times the Regulation Capacity clearing price.

(2) A service payment equal to the amount of service provided, while the Resource is considered to be performing as specified in Section III.14.7, as measured by the absolute value of the Resource's scheduled movement at the claimed rate of response without delay, in megawatts, toward the AGC SetPoint in response to AGC dispatch signals times the Regulation Service clearing price.

(ii) Calculation of Actual Energy Opportunity Costs.

A Resource-specific Regulation energy opportunity cost for those Resources dispatchable in the Real-Time Energy Market is determined for each five-minute interval that the Resource is selected to provide Regulation. The Regulation energy opportunity cost shall be equal to the product of (i) the absolute value of the deviation of the Resource's dispatch level necessary to follow the ISO's Regulation signals from the Resource's expected dispatch level if it had been dispatched in economic merit order and (ii) the absolute value of the difference between the Real-Time Price at the Node associated with the Resource and the megawatt weighted average Supply Offer or Demand Bid price for the energy associated with the deviation of the Resource's expected dispatch level if it had been dispatched in economic merit order. The Regulation energy opportunity cost for a Resource that is dispatched pursuant to Section III.1.10.9(e) shall be equal to zero for the settlement interval. Regulation energy opportunity costs are only incurred when a Resource is providing Regulation.

(iii) Make-Whole Payment

If revenues from the Regulation Capacity clearing price and the Regulation Service clearing price are insufficient to cover a Market Participant's as-bid costs for the actual Regulation Capacity and the amount of Regulation Service provided during a settlement interval plus actual energy opportunity costs as calculated in Section III.14.8(b)(ii), a make-whole payment will be provided for the period that the Resource is considered to be performing as specified in Section III.14.7.

(iv) Performance Adjustments.

A selected Resource's capacity payment will be reduced to reflect the proportion of time the Resource was determined to be non-performing pursuant to Section III.14.7.

(v) Compensation for Replacement Resources

If system conditions require the ISO to designate additional Resources in order to satisfy Regulation requirements for the remainder of a settlement interval without completing the selection process described in Section III.14.5, compensation for replacement Resources will be made according to the Resource's actual performance using the Regulation Capacity clearing price, the Regulation Service clearing price, and any make-whole payments as specified in Section III.14.8(b)(iii).

(c) Regulation Charges.

Each Market Participant shall have a Regulation charge equal to its pro rata share of the Regulation Capacity Requirement and Regulation Service Requirement for the settlement interval based on the Market Participant's total Real-Time Load Obligation. The total cost of providing Regulation for each settlement interval is charged to Market Participants based on their pro rata share of Real-Time Load Obligation during the period. For the purposes of allocating Regulation charges, the Real-Time Load Obligation of a Dispatchable Asset Related Demand providing Regulation shall be limited to the Minimum Consumption Limit of the Resource. Calculation of Regulation charges shall exclude contributions to Real-Time Load Obligations from Coordinated External Transactions.

(d) Net Energy Settlement for Alternative Technology Regulation Resources.

A Market Participant with an Alternative Technology Regulation Resource that is interconnected and metered at a single location may register the resource as a combination of the following asset types for the purpose of regulation energy market settlement:

- 1) an Alternative Technology Regulation Resource for the settlement of regulation capacity and regulation service;
- 2) a Settlement-Only Generator, if not greater than or equal to 5 MW, or otherwise a non-dispatchable, non-regulation capable Generator Asset for settlement of net energy injections that result from following AGC dispatch instructions;
- 3) an Asset Related Demand for settlement of net energy consumption; and
- 4) a load asset for settlement of net energy consumption for which the Real-Time Load Obligation is separately reported to the ISO.

III.14.9 Regulation Market Testing Environment.

The ISO administers a regulation resource test environment that allows Market Participants to evaluate or demonstrate the performance of Resources without an operational history of providing Regulation prior to participation in the Regulation Market.

Resources providing Regulation under the regulation resource test environment will be compensated for the Regulation Capacity and Regulation Service provided in response to AGC SetPoints at the lowest of the Regulation Capacity Offer prices and Regulation Service Offer prices offered for any Resource selected during each settlement interval. Resources that are also dispatchable in the Real-Time Energy Market will be compensated for Regulation energy opportunity costs incurred while operating under the regulation resource test environment.

Resources performing a minimal responsiveness test will not be compensated for Regulation.

A Resource may only provide Regulation under the regulation test environment until sufficient operational information has been collected to verify reasonable operating parameters for the Resource or to determine that the Resource does not meet the eligibility requirements necessary to participate in the Regulation Market.

SECTION III

MARKET RULE 1

APPENDIX A

**MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION**

APPENDIX A
MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this *Appendix A*.

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this *Appendix A* shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this *Appendix A*. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this *Appendix A*.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this *Appendix A*, the provisions of *Appendix A* shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III.A.17.3 are also part of the Participants Agreement and cannot be modified in either *Appendix A* or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this *Appendix A* are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

- (a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this *Appendix A*). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its

identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

- (b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.
- (c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the External Market Monitor shall perform the following functions:

- (a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this *Appendix A*, in accordance with the provisions of Section III.A.17 of this *Appendix A*.

- (c) Conduct evaluations and prepare reports on its own initiative or at the request of others.
- (d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this *Appendix A*.
- (f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.
- (g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this *Appendix A*, as appropriate.
- (h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the Internal Market Monitor shall perform the following functions:

- (a) Maintain *Appendix A* and consider whether *Appendix A* requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.
- (b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this *Appendix A*.
- (c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this *Appendix A*.
- (d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this *Appendix A*.
- (e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.
- (g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this *Appendix A*.
- (h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

- (i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this *Appendix A*.
- (j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this *Appendix A* are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

- (i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.
- (ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.
- (iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this *Appendix A*.
- (iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this *Appendix A*.
- (v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend *Appendix A* as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of

the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

- (i) Anti-competitive gaming of Resources;
- (ii) Conduct and market outcomes that are inconsistent with competitive markets;
- (iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;
- (iv) Actions in one market that affect price in another market;
- (v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this *Appendix A*, interfere with efficient market operation, both short-run and long-run; and
- (vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this *Appendix A*. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this *Appendix A*. If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

- (l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.
- (m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with *Appendix B* of this Market Rule I.

- (n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this *Appendix A* for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule 1 (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this *Appendix A*. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this *Appendix A*, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under *Appendix B* of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

- (a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:
- (b) Notwithstanding the foregoing or any other provision of this *Appendix A*, and as more fully described in Section III.B.3.2.6 of *Appendix B* to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This Appendix A.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this *Appendix A*, it may make a filing under §205 of the Federal Power Act (“§205”) with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor’s justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this *Appendix A* or in *Appendix B* to this Market Rule 1.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant. In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this *Appendix A*, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this *Appendix A* for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

- (a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.
- (b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer

or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus \$2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1 or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2

2 or more	6
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III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

- (a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
- (b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,
- (c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
- (d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

- (a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
- (b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

- (c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

- (a) all Supply Offer parameters shall be reviewed for economic withholding;
- (b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;
- (c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

- (a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;
- (b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

- (a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;
- (b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than \$25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

- (a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
- (b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or \$100/MWh, whichever is lower. Offer block prices below \$25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or \$100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or \$25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or \$25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

- i. local first contingency;
- ii. local second contingency;
- iii. VAR or voltage;
- iv. distribution (Special Constraint Resource Service);
- v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

- (a) If the Resource is starting from an offline state, the Start-Up Fee;
- (b) The sum of the No Load Fees for the Commitment Period; and
- (c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 “General Threshold Energy Mitigation” or III.A.5.5.2 “Constrained Area Energy Mitigation” is in effect for the following duration:

- (a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:
 - i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,
 - ii. for constrained area energy mitigation, the Resource is not located within a constrained area.
- (b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 “Constrained Area Energy Mitigation”), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 “Manual Dispatch Energy Mitigation” is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource’s Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 “General Threshold Commitment Mitigation”, III.A.5.5.5 “Constrained Area Commitment Mitigation”, or III.A.5.5.6 “Reliability Commitment Mitigation” is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 “Start-Up Fee and No-Load Fee Mitigation” is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as

part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

- (a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.
- (b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.
- (c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Supply Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of a Supply Offer according to the following hierarchy, under which the first method that can be calculated is used:

- (a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
- (b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
- (c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

- (a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
- (b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
- (c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
- (d) For any Operating Day for which, during the previous 90 days:
 - (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
 - (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
 - (iii) The Market Participant submits a fuel price pursuant to Section III.A.3.4.

For the purposes of this subsection:

- i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.
 - ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.
 - iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.
 - iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.
- (e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.
- (f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:
 - (i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,
 - (ii) No-Load Fee or its corresponding fuel blends,
 - (iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,
 - (iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and
 - (v) whether to use the offer slope for the Supply Offer,then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant through the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

- (a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".
- (b) Costs must be documented.
- (c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible.
- (d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.
- (e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:
 - i. Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected

- natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and
- ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy:

$(\text{incremental heat rate} * \text{fuel costs}) + (\text{emissions rate} * \text{emissions allowance price}) + \text{variable operating and maintenance costs} + \text{opportunity costs.}$

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

- (a) emissions limits;
- (b) water storage limits; and,
- (c) other operating permits that limit production of energy.

No-Load:

$(\text{no-load fuel use} * \text{fuel costs}) + (\text{no-load emissions} * \text{emission allowance price})$
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up:

$(\text{start-up fuel use} * \text{fuel costs}) + (\text{start-up emissions} * \text{emission allowance price}) + \text{start-up variable and maintenance costs} + \text{other start-up costs that are not fuel, emissions or variable and maintenance costs.}$

III.A.8. Determination of Offer Competitiveness During Capacity Scarcity Condition.

The Internal Market Monitor shall evaluate the competitiveness of the Supply Offer of each Resource with a Capacity Supply Obligation that is off-line during a Capacity Scarcity Condition, as described

below. The evaluation for competitiveness shall be performed on Supply Offers in the Day-Ahead Energy Market and on Supply Offers in the Real-Time Energy Market. For purposes of these evaluations, Reference Levels are calculated using the cost-based method specified in Section III.A.7.5. The Real-Time Energy Market evaluation uses the final Supply Offer in place for the hour.

- (a) Hours Evaluated. For Supply Offers in the Day-Ahead Energy Market, competitiveness is evaluated for all hours of the Operating Day during which a Shortage Event Capacity Scarcity Condition occurs. For Supply Offers in the Real-Time Energy Market competitiveness is evaluated for the last hour that the Resource could have been committed to be online at its Economic Minimum Limit at the start of the Shortage Event Capacity Scarcity Condition, taking into account the Resource's Start-Up Time and Notification Time.
- (b) Competitiveness Evaluation of Energy Offer At Low Load.
 - (i) If the Resource is not in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.
 - (ii) If the Resource is in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.
- (c) Competitiveness Evaluation of Energy Offer Above Low Load. If a Supply Offer evaluated for competitiveness pursuant to Section III.A.8 (b) above is competitive for an hour, then the energy price parameter for each incremental Supply Offer block above the Resource's Economic Minimum Limit shall be evaluated for competitiveness using the thresholds identified in Section III.A.5.5.1.2, for Resources not in a constrained area, and the thresholds identified in Section III.A.5.5.2.2, for Resources in a constrained area, in order of lowest energy price to highest energy price. If any Supply Offer block is non-competitive, then that block and all blocks above it shall be non-competitive, and all blocks below it shall be competitive.
- (d) Low Load Cost test. Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit for its Minimum Run Time, is calculated as the sum of:
 - i. The Start-Up Fee (cold start);
 - ii. The sum of the No Load Fees for the Resource's Minimum Run Time; and
 - iii. The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Resource's Minimum Run Time.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer Block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer Block.

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor ~~Demand Resources~~ the Energy Market as outlined below:

- (a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.
- (b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$$(\text{LMP}_{\text{real time}} / \text{LMP}_{\text{day ahead}}) - 1.$$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

- (i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.
- (ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.
- (iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England

Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

- (a) [Reserved].
- (b) Section III.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.
- (c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.
- (d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.

(e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.

(f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

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 Market Participant in accordance with Section III.A.3 of this *Appendix A*. 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 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer *Appendix B* in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.

Article 5 of the form of Cost-of-Service Agreement in *Appendix I* to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Filing Right.

If either

- (a) as a result of mitigation applied to a Resource under this *Appendix A* for all or part of one or more Operating Days, or
- (b) in the absence of mitigation, despite having submitted a Supply Offer at the Energy Offer Cap,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for the hours of the Operating Day during which the Supply Offer was mitigated or during which the Resource was operated at the Energy Offer Cap, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having submitted a Supply Offer at the Energy Offer Cap, costs incurred for the duration of the period of time for which the Resource was operated at the Energy Offer Cap.

III.A.15.2. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating

the Resource exceeded the costs as reflected in the Supply Offer at the Energy Offer Cap; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.

III.A.15.4. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in *Appendix D* to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.
- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully

challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this *Appendix A*, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

- (a) the opportunity costs associated with Demand Reduction Offers;

- (b) the accuracy of Demand Response Baselines;
- (c) the method used to achieve a demand reduction, and;
- (d) the accuracy of ~~reported-metered~~ demand reported to the ISO levels.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this *Appendix A* and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this *Appendix A*.

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion

of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this *Appendix A*.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of *Appendix A*. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

- (i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.
- (ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.
- (iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.
- (iv) Review and assessment of the effectiveness of *Appendix A* and the administration of *Appendix A* by the Internal Market Monitor for consistency and compliance with the terms of *Appendix A*.
- (v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

- (a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;
- (b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;
- (c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,
- (d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets (“authorized government agencies”). With respect to state regulatory bodies and state attorneys general (“authorized state agencies”), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government

agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as *Exhibit 5*.

III.A.18.2. Additional Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of *Appendix A*, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the

Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

- (B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information
 - (1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);
 - (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
 - (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
 - (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
 - (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;
 - (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
 - (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

- (A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.
- (B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information.
- (1) A detailed narrative describing the perceived market design flaw(s);
 - (2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;
 - (3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;
 - (4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.3-4 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the ~~Ninth~~ Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the twelfth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2021) shall be as follows:

Generating on Capacity Resources	
Technology Type	Offer Review Trigger Price (\$/kW-month)
combustion turbine	\$6.503
combined cycle gas turbine	\$7.856
on-shore wind	\$11.025

Demand Capacity Resources - Commercial and Industrial	
Technology Type	Offer Review Trigger Price (\$/kW-month)
Load Management and/or previously installed Distributed Generation	\$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	\$0.000

Demand Capacity Resources – Residential	
Technology Type	Offer Review Trigger Price (\$/kW-month)
Load Management	\$7.559

previously installed Distributed Generation	\$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	\$0.000

Other Resources

All other technology types	Forward Capacity Auction Starting Price
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Where a new resource is composed of assets having different technology types, the resource’s Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the aNew Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders

and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For ~~n~~New ~~generation-Generating Capacity~~ ~~#R~~Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For ~~n~~New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for ~~n~~New ~~generation-Generating Capacity~~ ~~#R~~Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For ~~n~~New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for ~~n~~New ~~generation-Generating Capacity~~ ~~#R~~Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	Index
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"
steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay: <ul style="list-style-type: none"> - Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts - On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
other labor	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: <ul style="list-style-type: none"> - Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts - On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"
fuel inventories	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	Index
labor, administrative and general	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: <ul style="list-style-type: none"> - Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts - On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit

	Price Deflator (GDPDEF)”
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(3) For each line item in (1) and (2) above, the ISO shall calculate -a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the ~~ninth~~-FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the ~~ninth~~-FCA reflected in the table in Section A.21.1.1 above will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub On-Peak electricity prices for the months in the Capacity Commitment Period beginning June 1, 2021, as published by ICE.

(5) Renewable energy credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO’s web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.~~1.1.2.82-4~~, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be \$0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.~~1.1.2.82-4~~, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted

cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a ~~#~~New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred ~~by the Demand Response provider and end use customers~~ to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Demand Asset(s)Resource.

(iii) For a ~~#~~New eCapacity ~~#~~Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to

participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification

determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.21.3. — Special Treatment of Certain Out-of-Market Capacity Resources in the Eighth Forward Capacity Auction.

~~For the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017), the provisions of Sections III.A.21.1 and III.A.21.2 shall also apply to certain resources that cleared in the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2015) and/or the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2016), as follows:~~

~~(a) This Section III.A.21.3 shall apply to: (i) any capacity clearing in the sixth or seventh Forward Capacity Auction as a New Generating Capacity Resource or New Import Capacity Resource designated as a Self-Supplied FCA Resource; and (ii) any capacity clearing in the sixth or seventh Forward Capacity Auction from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at prices found by the Internal Market Monitor to be not consistent with either: (a) the resource's long run average costs net of expected net revenues other than capacity revenues for a New Generating Capacity Resource and a New Demand Resource or (b) opportunity costs for a New Import Capacity Resource.~~

~~(b) For the eighth Forward Capacity Auction, the capacity described in subsection (a) above shall receive Offer Review Trigger Prices as described in Section III.A.21.1 and New Resource Offer Floor Prices as described in Section III.A.21.2. These values will apply to such capacity in the conduct of the eighth Forward Capacity Auction as described in Section III.13.2.3.2.~~

~~(c) For the eighth Forward Capacity Auction, the Project Sponsor or Lead Market Participant for such capacity may be required to comply with some or all of the qualification provisions applicable to new resources described in Section III.13.1. These requirements will be determined by the ISO on a case-by-case basis in consultation with the Project Sponsor or Lead Market Participant.~~

~~(d) For any capacity described in subsection (a) above that does not clear in the eighth Forward Capacity Auction:~~

~~(i) any prior election to have a Capacity Clearing Price and Capacity Supply Obligation continue to apply for more than one Capacity Commitment Period made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 shall be terminated as of the beginning of the Capacity Commitment Period associated with the eighth FCA (beginning June 1, 2017); and~~

~~(ii) after the eighth Forward Capacity Auction, such capacity will be deemed to have never been previously counted as capacity, such that it meets the definition, and must meet the requirements, of a new capacity resource for the subsequent Forward Capacity Auction in which it seeks to participate.~~

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

- (a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;
- (b) For each modeled import-constrained Capacity Zone, the greater of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
- (c) For each modeled export-constrained Capacity Zone, the lesser of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone plus, for each external interface connected to the export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Maximum Capacity Limit of the export-constrained Capacity Zone, and;
- (d) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

- (e) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone; and
- (f) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

- (a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.
- (b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand [Capacity](#) Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, “control” or “controlled” means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

- i. The annual capacity revenue from the Lead Market Participant’s total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than
- ii. the annual capacity revenue from the Lead Market Participant’s total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List

- Bid or Retirement De-List Bid, then
- iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

- iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.
- v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.
- vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of

the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

SECTION III

MARKET RULE 1

APPENDIX E

[RESERVED]

~~DEMAND RESPONSE~~

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DEMAND RESPONSE
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~~APPENDIX E2~~
~~DEMAND RESPONSE~~

~~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 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 capability 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 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 $\pm 2.0\%$; 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 $\pm 2.0\%$; 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 electrically 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 $\pm 2.0\%$. 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 $\pm 2.0\%$ 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:~~

$$~~DRTP = P_{th} \tilde{\Lambda} \frac{FPI_G}{FPI_R}~~$$

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 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 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.~~

**SECTION III
MARKET RULE 1**

**APPENDIX F
NET COMMITMENT PERIOD COMPENSATION ACCOUNTING**

APPENDIX F
NCPC ACCOUNTING
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NCPC ACCOUNTING

III.F.1. General.

For purposes of NCPC calculations:

- a. **Effective Offers.** An Effective Offer for a Resource is (1) the Supply Offer, ~~or Demand Reduction Offer, or~~ Demand Bid used in making the decision to commit the Resource; and (2) the Supply Offer, ~~Demand Reduction Offer,~~ or Demand Bid used in making the decision to dispatch the Resource at a Desired Dispatch Point above its Economic Minimum Limit, Minimum Reduction, or ~~at or above a DARD Pump's~~ Minimum Consumption Limit, and is subject to the following conditions:
- i. The Effective Offer used in making the decision to commit the Resource establishes the parameters used for NCPC calculations, including the quantity and price pairs for output, demand reduction, or consumption up to the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit; the Start-Up Fee, ~~the~~ No-Load Fee, or Interruption Cost; and the operating limits ~~used for NCPC calculations~~.
 - ii. In the event the Resource's Economic Minimum Limit, ~~or Minimum Reduction, or~~ Minimum Consumption Limit is increased after the decision to commit the Resource, the energy price parameter for output, demand reduction, or consumption at the Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit used in making the decision to commit the Resource will be applied as the energy price parameter for additional output, demand reduction, or consumption up to the increased Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit.
 - iii. In the event a Minimum Generation Emergency is declared, the Economic Minimum Limit will be replaced with the Emergency Minimum Limit for purposes of determining the energy price parameter of the Effective Offer.
 - iv. The Effective Offer takes account of mitigation applied to the Supply Offer, whether performed prior to or after the commitment or dispatch decision is made.
 - v. The Effective Offer takes account of a reduction in the energy price parameter, the Start-Up Fee, ~~or~~ the No-Load Fee, or the Interruption Cost in a Supply Offer or Demand Reduction Offer; or an increase in the energy price parameter of a Demand Bid that is made prior to the end of the Resource's Commitment Period.
 - vi. In the event the ISO approves the Resource's synchronization to the system as a Pool-Scheduled Resource earlier than its scheduled time, the Effective Offer takes account of the

lesser of the energy price parameter, the Start-Up Fee and the No-Load Fee in place for the scheduled Commitment Period or the actual early release-for-dispatch time.

- vii. A Resource that is online providing synchronous condensing is considered to be in a hot temperature state for the purpose of determining the Start-Up Fee for the Effective Offer when the Resource is requested to switch from synchronous condensing to provide energy.

b. Treatment of Self-Schedules.

- i. In the Day-Ahead Energy Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to \$0, a No-Load Fee equal to \$0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to the minimum of the Energy Offer Floor and the Day-Ahead Price; or, in the case of a DARD Pump, is treated as having a Demand Bid with an energy price parameter for consumption up to its Minimum Consumption Limit equal to the maximum of the Energy Offer Cap and the Day-Ahead Price. Any amounts (MW) offered or bid above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid.
- ii. In the Real-Time Energy Market, a Resource that is committed as a Self-Schedule is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to \$0, a No-Load Fee equal to \$0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to \$0/MWh; or (ii) as having a Demand Bid for consumption up to the Minimum Consumption Limit at the Energy Offer Cap. Any amounts (MW) offered above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid. For any hour for which a Resource is dispatched pursuant to Section III.1.10.9(e), the Start-Up Fee and No-Load Fee are equal to \$0.
- iii. If the Resource's Supply Offer contains a Self-Schedule for fewer contiguous hours than its Minimum Run Time, the minimum number of additional hours required to satisfy the Resource's Minimum Run Time will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market. If the Resource is committed for one or more hours immediately prior to and contiguous with the Self-Schedule, the hours of that prior Commitment Period will be counted toward satisfying the Resource's Minimum Run Time before hours subsequent to the Self-Schedule are counted. If the Resource's Supply Offer contains two Self-Schedules separated by less than the Resource's Minimum Down Time, the

hours between the two Self-Schedules will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market.

- c. **Sub-Hourly Intervals.** If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.
- d. **Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Minimum Run Time or Minimum Reduction Time Carries Into Second Operating Day.** If a Resource that is committed in either (i) the Day-Ahead Energy Market, or (ii) the Resource Adequacy Analysis prior to the start of the Operating Day must continue to operate across an Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for hour ending 24 of the Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day. If a Resource that is committed during the Operating Day must continue to operate across the Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the second Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day.
- e. **Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Committed Prior to Day-Ahead Energy Market.** If a Resource is committed for an Operating Day prior to the Day-Ahead Energy Market, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the Operating Day at the time of the commitment is used to establish the Effective Offer for the period of the commitment.
- f. **Eligibility for NCPC Credits When Performing Audits or Facility and Equipment Testing.** The Real-Time NCPC Credit calculation for a Resource performing an audit uses the Start-Up Fee, No-Load Fee, Interruption Cost, Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction in the Effective Offer applicable to the Commitment Period during which the audit is conducted, and does not take account of any increases to the Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction value that take place in the course of the audit.
- Market Participants are not eligible for NCPC Credits when conducting audits or Facility and Equipment Testing under the following conditions:

- i. When a Market Participant requests that some hours of the commitment of a Pool-Scheduled Resource be used to satisfy an audit, and the Market Participant has changed the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit for those hours for the purpose of conducting the audit, the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- ii. When a Market Participant Self-Schedules a Resource to perform the audit, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the Self-Schedule and is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- iii. When a Market Participant requests that an audit be performed that requires the ISO to dispatch the Resource for the audit without advance notice to the Market Participant, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment or Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- iv. When an ISO-Initiated Claimed Capability Audit is performed pursuant to III.1.5.1.4, the Market Participant is not eligible for Real-Time Commitment NCPC Credits or Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted if both of the following are true:
 1. the Resource had a summer or winter Seasonal Claimed Capability or Seasonal DR Audit value equal to 0 MW at the beginning of the current Capability Demonstration Year, and
 2. the ISO Initiated Claimed Capability Audit is the first Claimed Capability Audit that the Resource performs during that Capability Demonstration Year.
- v. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Pool-Scheduled Resource, the Economic Minimum Limit (or Minimum Consumption Limit for a DARD Pump) in place at the time of the commitment decision is used for calculating Real-Time Commitment NCPC Credits and the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.

vi. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Resource that Self-Scheduled, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment and is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.

~~The Real-Time NCPC Credit calculation for a Resource performing an audit uses the Start-Up Fee, No-Load Fee and Economic Minimum Limit or Minimum Consumption Limit in the Effective Offer applicable to the Commitment Period during which the audit is conducted, and does not take account of any increases to the Economic Minimum Limit or Minimum Consumption Limit value that take place in the course of the audit.~~

g. Coordinated External Transactions are Not Eligible for NCPC and are excluded from NCPC Charges. Notwithstanding anything to the contrary in this Appendix F, Market Participants are not eligible to receive NCPC Credits for Coordinated External Transactions purchases or sales and shall be excluded from all NCPC Charge calculations under this Appendix F.

h. Demand Response Resource Credit Calculations. Where indicated in Section III.F.2, the costs and revenues for a Demand Response Resource, other than those associated with Net Supply or Interruption Costs, are increased by average avoided peak distribution losses.

h.i. Following Dispatch Instructions.

i. ~~For the purpose of allocating NCPC costs, a Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit greater 50 MWs is considered to be following a dispatch instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 10% above its Desired Dispatch Point and not less than 10% below its Desired Dispatch Point for each interval in the hour. Generating-A Resources with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit less than or equal to 50 MWs are is considered to be following a Dispatch Instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 5 MWs above its Desired Dispatch Point and is not less than 5 MWs below its Desired Dispatch Point for each interval in the hour. If the Resource violates this criterion in any interval during the hour, the Resource is considered to be not following Dispatch Instructions for the entire hour.~~

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- ii. DNE Dispatchable Generators are considered to be following Dispatch Instructions if the actual output of the DNE Dispatchable Generator is at or below its Do Not Exceed Dispatch Point.

III.F.2. NCPC Credits

III.F.2.1 Day-Ahead Energy Market NCPC Credits

III.F.2.1.1. Eligibility for Credit. ~~All Market Participants with an Ownership Share in a Resource Generator Asset~~ with a Supply Offer, ~~a Demand Response Resource with a Demand Reduction Offer,~~ or a DARD Pump with a Demand Bid that clears the Day-Ahead Energy Market in an hour ~~are~~ is eligible for Day-Ahead Energy Market NCPC Credits for the hour.

III.F.2.1.2. Settlement Period. For ~~a Generator Asset, a Demand Response Resource, or a DARD Pump,~~ for purposes of calculating Day-Ahead Energy Market NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day for which a Resource has cleared in the Day-Ahead Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator ~~or to or from a Fast Start Demand Response Resource,~~ or any time a DNE Dispatchable Generator's operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation.

III.F.2.1.3. Eligible Quantity. ~~For a Generator Asset, Demand Response Resource, or DARD Pump,~~ ~~t~~he eligible quantity of energy ~~for a Resource~~ is the amount of energy the Resource clears in the Day-Ahead Energy Market for each hour of the settlement period.

III.F.2.1.3A Hourly Bid. ~~The hourly bid f~~or a DARD Pump, ~~the hourly bid~~ is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each hour of the settlement period.

III.F.2.1.4 Hourly Cost. ~~The hourly cost for a DARD Pump is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity.~~

~~(a) The hourly cost for a~~ Generator Asset, Resource other than a DARD Pump ~~the hourly cost~~ is equal to the energy price parameter for the eligible quantity, the Start-Up Fee and the No-Load Fee as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2 ~~the following conditions.~~

~~(b) For a Demand Response Resource, the hourly cost is equal to the energy price parameter for the eligible quantity and the Interruption Cost as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.~~

~~(c) For a DARD Pump, the hourly cost is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity.~~

III.F.2.1.4.1 ~~For a Generator Asset or a Demand Response Resource, the~~ Start-Up Fee or Interruption Cost is apportioned equally over the hours from the time the Resource is scheduled to begin its commitment through the end of the Commitment Period during which the Minimum Run Time or Minimum Reduction Time is scheduled to expire.

III.F.2.1.4.2 ~~For a Generator Asset or a Demand Response Resource, when~~ the period of hours over which the Start-Up Fee or Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee or Interruption Cost.

III.F.2.1.5 **Hourly Revenue.** ~~For a Generator Asset or a Demand Response Resource, the~~ hourly revenue ~~for a Resource~~ is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity for the Resource.

III.F.2.1.6 **General Credit Calculation.** Except as provided in Section III.F. 2.1.7 below, the Day-Ahead Energy Market NCPC Credit for a Resource, adjusted as described in III.F.1(h), is equal to:

(a) For ~~Resources other than DARD Pumps~~ a Generator Asset or a Demand Response Resource: the greater of (i) zero, and; (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly revenue for the Resource in all hours of the settlement period, where the costs and revenues of a Demand Response Resource, other than those associated with Interruption Costs, are increased by average avoided peak distribution losses; and

(b) For a DARD Pump: the greater of: (i) zero and (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly bids in all hours of the settlement period.

III.F.2.1.7 Credit Calculation for Fast Start Generators, ~~DARD Pumps and~~ Flexible DNE Dispatchable Generators, Fast Start Demand Response Resources and DARD Pumps Based on Daily Starts.

—If the number of daily starts for a Fast Start Generator, ~~DARD Pump or~~ Flexible DNE Dispatchable Generator, Fast Start Demand Response Resource or DARD Pump is less than the resource's Maximum Number of Daily Starts, then the resource's Day-Ahead Energy Market NCPC Credit, adjusted as described in III.F.1(h), is calculated as follows:

- (a) ~~The Day-Ahead Energy Market NCPC Credit for~~ a Fast Start Generator, ~~or~~ a Flexible DNE Dispatchable Generator or a Fast Start Demand Response Resource, the Day-Ahead Energy Market NCPC Credit is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for the Resource in an hour minus the hourly revenue for the Resource in that hour.
- (b) ~~The Day-Ahead Energy Market NCPC Credit for~~ a DARD Pump, the Day-Ahead Energy Market NCPC Credit is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the total hourly cost for the Resource in an hour minus the total hourly bid for the Resource in that hour.

III.F.2.2 Real-Time Energy Market NCPC Credits

Real-Time Energy Market NCPC Credits include a Real-Time Commitment NCPC Credit, a Real-Time Dispatch NCPC Credit and a Real-Time Dispatch Lost Opportunity Cost NCPC Credit. For purposes of this Section III.F.2.2, unless otherwise expressly stated, costs and revenues shall be calculated at a five minute interval.

III.F.2.2.1 Eligibility for Credit.

(a) Commitment and Dispatch Credits – The following Resources are eligible for Real-Time Commitment NCPC Credits and Real-Time Dispatch NCPC Credits for some or all intervals of the hour: All Market Participants with an Ownership Share (i) in a Resource-Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; (iii) in a DARD Pump with a Demand Bid that has been submitted in the Real-Time Energy Market, or; (iv) in a DARD Pump that has been Postured to increase its consumption, are eligible for Real-Time Commitment NCPC Credits and Real-Time Dispatch NCPC Credits for some or all intervals of the hour.

~~(b) Dispatch Lost Opportunity Cost Credits - All Market Participants with an Ownership Share in a Resource- Generator Asset~~ with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or ~~in~~ a Dispatchable Asset Related Demand with a Demand Bid; that is committed and able to respond to Dispatch Instructions during the interval ~~are-is~~ eligible to receive a Real-Time Dispatch Lost Opportunity Cost NCPC Credits; provided, however, that such credit shall be zero if the Resource has been Postured or has provided Regulation during the interval.

III.F.2.2.2 Real-Time Commitment NCPC Credits

III.F.2.2.2.1 Settlement Period.

(a) For Generator Assets, Demand Response Resources, and DARD Pumps, for purposes of calculating Real-Time Commitment NCPC Credits, a settlement period is a period of one or more contiguous intervals in an Operating Day during which a Resource is ~~online and~~ operating pursuant to one or more commitments in the Day-Ahead Energy Market or Real-Time Energy Market.

(b) For Generator Assets and Demand Response Resources, a new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, ~~or any time a DNE Dispatchable Generator's operating characteristics change~~ to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.

~~(c)~~ (c) For Generator Assets and DARD Pumps, in the event of an interruption in operation of a Resource, operation will be considered contiguous if the Resource returns to operation in accordance with the original commitment issued prior to the interruption.

III.F.2.2.2.2 Eligible Quantity.

~~III.F.2.2.2.2.A For a DARD Pump, T~~he eligible quantity ~~for a DARD Pump~~ for each interval is the amount of energy equal to the lesser of its Economic Dispatch Point for that interval ~~or and the DARD Pump's its~~ Metered Quantity For Settlement for the interval.

III.F.2.2.2.2.1.

- (a) ~~For a Generator Asset, the eligible quantity is~~ For determining the interval costs used in calculating a Real-Time Commitment NCPC Credit, ~~the eligible quantity of energy for a Resource other than a DARD Pump~~ is the amount of energy equal to the lesser of the Resource's Metered Quantity For Settlement ~~or~~ and Economic Dispatch Point for the interval.

III.F.2.2.2.2

- (b) ~~For a Generator Asset, the eligible quantity is~~ For determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit, ~~the eligible quantity of energy for a Resource other than a DARD Pump~~ is the lesser of the Resource's Metered Quantity For Settlement ~~or~~ and Economic Dispatch Point for the interval, except that Metered Quantity For Settlement is used as the eligible quantity (i) when the Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) when the Resource is ramping from an offline state to be released for dispatch ~~and~~ or (iii) after the Resource has been released for shutdown.

III.F.2.2.2.2.2

- (a) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and its Economic Dispatch Point for the interval.
- (b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is equal to the eligible quantity used to determine interval costs pursuant to (a) above, except that the eligible quantity shall be the Metered Quantity For Settlement if any of the following are true: (i) the Demand Response Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time have not concluded, or (iii) the Demand Response Resource has received an instruction to stop reducing demand.

III.F.2.2.2.3. Interval Cost.

- (a) The interval cost for a Generator Asset is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Start-Up Fee and No-Load Fee as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1, III.F.2.2.2.3.2, and III.F.2.2.2.3.3.

(b) The interval cost for a Demand Response Resource is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Interruption Cost as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1 and III.F.2.2.2.3.2, provided that costs shall be set to \$0 for the interval when there is a negative demand reduction.

~~(a)(c)~~ The interval cost for a DARD Pump is the Real-Time Price for the interval multiplied by the eligible quantity. The interval cost is reduced by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval cost is also reduced by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5.

~~The interval cost for a Resource other than a DARD Pump is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Start-Up Fee and No-Load Fee as reflected in the Effective Offer, for each interval of the settlement period, subject to the following conditions:~~

III.F.2.2.2.3.1

(a) For a Generator Asset, the energy cost for an interval excludes the cost of (a) energy produced when the Resource is ramping from an offline state to be released for dispatch and (b) energy produced after the Resource has been released for shutdown.

~~(a)(b)~~ For a Demand Response Resource, the energy cost for an interval excludes the cost of (a) energy produced prior to the conclusion of the Demand Response Resource Start-Up Time and (b) energy produced after the Demand Response Resource has received an instruction to stop reducing demand.

III.F.2.2.2.3.2

(a) For a Generator Asset, the Start-Up Fee is apportioned equally over the intervals from the time the Resource-Generator Asset is released for dispatch through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire, subject to the following conditions:

(i) The Start-Up Fee is reduced in proportion to the number of minutes after 30 the Resource-Generator Asset is released for dispatch, as (measured from the time the Resource-Generator Asset was scheduled to be released for dispatch), divided by the time from when the Resource

Generator Asset was scheduled to be released for dispatch through the end of the Commitment Period during which the Minimum Run Time was scheduled to expire.

(ii) The Start-Up Fee is excluded from the interval cost calculation if the Resource-Generator Asset is synchronized to the system prior to its scheduled synchronization time without the ISO's approval of the Resource's-Generator Asset's synchronization as a Pool-Scheduled Resource.

(iii) The portion of the Start-Up Fee apportioned to any interval during which the Resource-Generator Asset is not online because the Resource-Generator Asset has tripped is excluded from the interval cost calculation, except in the event the Resource-Generator Asset is not online due to a trip that results from equipment failure involving equipment located on the electric network beyond the low voltage terminals of the Resource's-Generator Asset's step-up transformer. It is the responsibility of the Lead Market Participant for the Resource-Generator Asset to inform the ISO at xtrip@iso-ne.com within 30 days that the trip was the result of such a transmission-related event.

(iv) The Start-Up Fee is not reduced when the Resource-Generator Asset has shutdown with the ISO's approval prior to the end of its Commitment Period.

(v) The additional Start-Up Fee for a Resource-Generator Asset requested to re-start following a trip is apportioned equally over the remaining intervals of the Commitment Period when the ISO requests a Resource-Generator Asset to re-start to complete its Commitment Period.

(vi) When the period of intervals over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.

(b) For a Demand Response Resource, the Interruption Cost is apportioned equally over the intervals from the time the Demand Response Resource Start-Up Time concludes through the end of the Commitment Period during which the Minimum Reduction Time is scheduled to expire, subject to the following conditions:

(i) The Interruption Cost is reduced in proportion to the number of minutes after 30 the Demand Response Resource begins to provide a demand reduction (measured from the conclusion of the Demand Response Resource Start-Up Time), divided by the time from the conclusion of the Demand Response Resource Start-Up Time through the end of the Commitment Period during which the Minimum Reduction Time was scheduled to expire.

(ii) The portion of the Interruption Cost apportioned to any interval during which the Demand Response Resource is not providing a demand reduction because the Demand Response Resource has become unavailable to provide a reduction is excluded from the interval cost calculation.

(iii) The Interruption Cost is not reduced when the Demand Response Resource has stopped reducing demand with the ISO's approval prior to the end of its Commitment Period. When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.

(iv) When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.

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III.F.2.2.2.3.3. For a Generator Asset for each hour, the No-Load Fee is equally apportioned to each interval in the hour during the period when the Resource-Generator Asset is online following its release for dispatch and prior to its release for shutdown. The No-Load Fee is pro-rated for the hour during which the Generator Asset Resource is released for dispatch, the hour during which the Generator Asset Resource is released for shutdown, and any other hour during which the Generator Asset Resource operates for less than 60 minutes.

III.F.2.2.2.3.A Interval Bid. The interval bid for a DARD Pump is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each interval of the settlement period.

III.F.2.2.2.4 Interval Revenue. The interval revenue for a Generator Asset or Demand Response Resource is equal to the Real-Time Price for each interval of the settlement period multiplied by the eligible quantity for the interval. The revenue for an interval is increased by the amount by which the interval revenues in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.4 exceed the interval costs in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.3. The interval revenue is increased by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval revenue is also increased by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5. The revenues when the Generator Asset Resource is ramping from an offline state to be released for dispatch, or during the Demand Response Resource Start-Up Time, are apportioned equally to the intervals of the Minimum Run Time or Minimum Reduction Time.

III.F.2.2.2.4.1. ~~For a Generator Asset, Re~~venues for output up to the Resource's Economic Minimum Limit in a Self-Scheduled interval, calculated as the Real-Time Price multiplied by the output, are excluded from the revenue for the Real-Time Commitment NCPC Credit calculation.

III.F.2.2.2.4.2. For a Demand Response Resource, revenues shall be set to \$0 for the interval when the Locational Marginal Price is positive and there is a negative demand reduction.

III.F.2.2.2.5 **Credit Calculation for ~~Resources-Generator Assets and Demand Response Resources~~other than DARD Pumps.** The Real-Time Commitment NCPC Credit for a Generator Asset or a Demand Response Resource, adjusted as described in III.F.1(h) ~~other than a DARD Pump~~ is equal to:

- (a) ~~For~~ the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval revenue for the Resource for the period, plus,
- (b) ~~For~~ each remaining interval of the settlement period following the completion of the Minimum Run Time or Minimum Reduction Time, the greater of ((i) zero, and; (ii) the maximum potential net revenues for the Resource in the period) minus the actual net revenues for the Resource in the period, where
- (i) The maximum potential net revenue is the maximum accumulated net interval revenue for operating and then shutting down (or, for a Demand Response Resource, reducing demand and then ceasing to reduce demand) during the period.
 - (ii) The actual net revenue is the accumulated net interval revenue over the period.
 - (iii) The net interval revenue is the interval revenues minus interval costs in the period.

III.F.2.2.2.6. [Reserved.]

III.F.2.2.2.7 **Credit Calculation for DARD Pumps.** The Real-Time Commitment NCPC Credit for a DARD Pump is equal to:

(a) ~~F~~or the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval bid for the Resource for the period,

plus,

(b) ~~F~~or each remaining interval of the settlement period following the completion of the Minimum Run Time, the greater of ((i) zero, and; (ii) the maximum potential net benefit for the Resource in the period) minus the actual net benefit for the Resource in the period, where

(i) The maximum potential net benefit is the maximum accumulated net interval benefit for operating and then shutting down during the period.

(ii) The actual net benefit is the accumulated net interval benefit over the period.

(iii) The net interval benefit is the interval bid minus interval cost in the period.

III.F.2.2.2.8 Resources with Commitment in the Day-Ahead Energy Market (~~for Resources other than Fast Start Generators, Fast Start Demand Response Resources, and DARD Pumps~~).

(a) For purposes of calculating the interval cost under Section III.F.2.2.2.3, for any hour in which a Resource; ~~(other than a Fast Start Generator, Fast Start Demand Response Resource, or DARD Pump);~~ has a commitment in the Day-Ahead Energy Market, the Start-Up Fee, No-Load Fee, Interruption Cost and energy price parameter for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to \$0 for the hour. The Start-Up Fee shall not be set to \$0 in the case when a Resource re-starts at ISO request following a trip.

(b) For purposes of calculating the interval revenue under Section III.F.2.2.2.4, for any hour in which a Resource; ~~(other than a Fast Start Generator, Fast Start Demand Response Resource, or DARD Pump);~~ has a commitment in the Day-Ahead Energy Market, the revenue for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to \$0 for the hour if such revenue is less than \$0.

(c) Notwithstanding anything to the contrary in this Section III.F.2.2.2, a Generator Asset that cleared in the Day-Ahead Energy Market and performs an audit scheduled by the ISO pursuant to Section III.1.5.2(f) during all or part of its Day-Ahead schedule on a higher-priced fuel than that which formed the basis of the Generator Asset's Supply Offer in the Day-Ahead Energy Market shall receive additional compensation equal to:

i. For the MW quantity equal to the lesser of the Generator Asset's actual metered output and Economic Dispatch Point, the difference between 1) the incremental energy audit costs based on the Supply Offer 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; and
- ii. The difference between the No-Load Fee based on the Supply Offer using the fuel on which the audit was performed and the No-Load Fee for that same operation as reflected in the Day-Ahead Supply Offer; and
 - iii. Any additional Start-Up Fees incurred as a result of performing the audit.

III.F.2.2.3. Real-Time Dispatch NCPC Credits for Generator Assets and Demand Response Resources~~Resources other than DARD Pumps~~.

III.F.2.2.3.1 Settlement Period. For Generator Assets and Demand Response Resources, for purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement for a Resource are each greater than its Economic Dispatch Point, excluding any period of time when:

- (a) For a ~~the Resource~~ Generator Asset, the generator is ramping from an offline state to be released for dispatch, and after the ~~Resource~~ generator has been released for shutdown, or-
- (b) For a Demand Response Resource, prior to the conclusion of the Demand Response Start-Up Time and after the Demand Response Resource has received a Dispatch Instruction to stop reducing demand.

III.F.2.2.3.2. Eligible Quantity.

III.F.2.2.3.2.1.

(a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit, ~~the eligible quantity of energy for a Resource other than a DARD Pump with dispatchability above its Minimum Consumption Limit~~ is the ~~Resource's~~ generator's Economic Dispatch Point for the interval subtracted from the lesser of the ~~Resource's~~ generator's Metered Quantity For Settlement or Desired Dispatch Point for the interval.

(b) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Demand Response Resource's Economic Dispatch Point for the interval subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement and its Desired Dispatch Point for the interval.

III.F.2.2.3.2.2.

(a) For a Generator Asset, the eligible quantity Ffor determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit, ~~the eligible quantity of energy for a Resource~~ is the ~~Resource's generator's~~ Metered Quantity For Settlement for the interval minus the ~~Resource's-generator's~~ Economic Dispatch Point, except that the ~~Resource's-generator's~~ Economic Dispatch Point subtracted from the lesser of the ~~Resource's-generator's~~ Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval.

~~(a)~~(b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit equals the Demand Response Resource's Metered Quantity For Settlement for the interval minus the Demand Response Resource's Economic Dispatch Point, except that the Demand Response Resource's Economic Dispatch Point subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval.

III.F.2.2.3.3 Interval Cost. ~~For a Generator Asset or a Demand Response Resource, t~~The interval cost ~~for a Resource~~ is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer and does not include the Start-Up Fee, ~~or~~ the No-Load Fee, or the Interruption Cost.

III.F.2.2.3.4 Interval Revenue. ~~For a Generator Asset or a Demand Response Resource, t~~The interval revenue ~~for a Resource~~ is equal to the Real-Time Price multiplied by the eligible quantity, plus, for a Generator Asset, the portion of regulation opportunity costs attributed to operation in response to Regulation AGC dispatch signals at a level above the Resource's expected economic dispatch level, as specified in Section III.14.8(b)(ii).

III.F.2.2.3.5 Credit Calculation. For a Generator Asset or a Demand Response Resource, tThe Real-Time Dispatch NCPC Credit ~~for a Resource~~ in an interval is equal to the greater of (i) zero and (ii) the interval cost minus the interval revenue for the Resource, adjusted as described in III.F.1(h).

III.F.2.2.4 Real-Time Dispatch NCPC Credits for DARD Pumps

III.F.2.2.4.1 Settlement Period. For purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement are each greater than the DARD Pump's Economic Dispatch Point.

III.F.2.2.4.2 Eligible Quantity. The eligible quantity of energy is equal to the greater of (i) zero and (ii) the DARD Pump's Economic Dispatch Point for the interval subtracted from the lesser of the DARD Pump's Metered Quantity For Settlement or Desired Dispatch Point for the interval.

III.F.2.2.4.3 Interval Cost. The interval cost is the Real-Time Price for the interval multiplied by the eligible quantity.

III.F.2.2.4.4 Interval Bid. The interval bid is equal to the energy price parameter for the eligible quantity as reflected in the Demand Bid for each interval of the settlement period.

III.F.2.2.4.5 Credit Calculation. The Real-Time Dispatch NCPC Credit for an eligible DARD Pump in an interval is equal to the greater of: (i) zero, and; (ii) the interval cost minus the interval bid in that interval.

III.F.2.2.5. Real-Time Dispatch Lost Opportunity Cost NCPC Credits

III.F.2.2.5.1. Maximum Net Revenue or Maximum Net Benefit.

~~(a) For a Generator Asset or a Demand Response Resource, the maximum net revenue for a Resource other than a Dispatchable Asset Related Demand~~ during the interval is the Resource's energy revenue at the Economic Dispatch Point, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point, as described in III.F.1(h).

~~(b) The maximum net benefit for~~ a Dispatchable Asset Related Demand, the maximum net benefit during the interval is the Resource's energy price parameter for the Economic Dispatch Point as reflected in the Demand Bid, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point.

III.F.2.2.5.2. Actual Net Revenue or Actual Net Benefit.

~~(a) The actual net revenue for a Resource other than a Dispatchable Asset Related Demand-Generator Asset or Demand Response Resource shall be the sum, adjusted as described in III.F.1(h), of the following two values:~~

- (i) ~~is~~ the greater of: ~~(i1)~~ the energy revenue at the Metered Quantity For Settlement minus the offered energy cost for that quantity; and ~~(i2)~~ the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity: ~~and~~;

~~plus~~

- ~~(ii)~~ the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.

~~(b)~~ The actual net benefit for a Dispatchable Asset Related Demand shall be the sum of the following two values:

- (i) ~~is~~ the greater of: ~~(i1)~~ the energy price parameter for the Metered Quantity For Settlement as reflected in the Demand Bid minus the offered energy cost for that quantity; and ~~(i2)~~ the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity: ~~and~~;

~~plus~~

- ~~(ii)~~ the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.

III.F.2.2.5.3. Credit Calculation. For a Generator Asset, a Demand Response Resource, or a Dispatchable Asset Related Demand, ~~the~~ Real-Time Dispatch Lost Opportunity Cost NCPC Credit ~~for a Resource~~ is equal to the greater of: (i) zero; and (ii) the Resource's maximum net revenue or benefit for the interval less its actual net revenue or benefit for the interval.

The Dispatch Lost Opportunity Cost NCPC Credit for a Resource for an interval shall be reduced by the amount of any Rapid Response Pricing Opportunity Cost NCPC Credits for which the Resource is eligible for that interval, but shall be no less than zero.

III.F.2.3. Special Case NCPC Credit Calculations

III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits

III.F.2.3.1.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction imports or Increment Offers at an External Node are eligible for Day-Ahead External Transaction Import and Increment Offer NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.1.2. Hourly Offer. The Day-Ahead offer for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the offer price.

III.F.2.3.1.3. Hourly Revenue. The Day-Ahead revenue for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price.

III.F.2.3.1.4. Credit Calculation. A Day-Ahead External Transaction Import and Increment Offer NCPC Credit for an External Transaction import or Increment Offer, for an hour, is equal to any portion of the Day-Ahead offer in excess of the Day-Ahead revenue for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction import or Increment Offer for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction export or Decrement Bid for the same External Node and hour, the Day-Ahead External Transaction Import and Increment Offer NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction import or Increment Offer at the External Node for the hour that is not offset by the amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour. If multiple External Transaction imports or Increment Offers at an External Node are eligible for a Day-Ahead External Transaction Import and Increment Offer NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction imports and Increment Offers will be offset in order from the highest to the lowest-priced transactions or offers.

III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits

III.F.2.3.2.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction exports or Decrement Bids at an External Node are eligible for Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.2.2. Hourly Bid. The Day-Ahead bid for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the bid price.

III.F.2.3.2.3. Hourly Cost. The Day-Ahead cost for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price at the External Node.

III.F.2.3.2.4. Credit Calculation. A Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for an External Transaction export or Decrement Bid, for an hour, is equal to any portion of the Day-Ahead hourly cost in excess of its Day-Ahead hourly bid for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction export or Decrement Bid for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction import or Increment Offer for the same External Node and hour, the Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour that is not offset by the amount (MW) of the total cleared External Transaction import or Increment Offer at the External Node for the hour. If multiple External Transaction exports or Decrement Bids at an External Node are eligible for a Day-Ahead External Transaction Export and Decrement Bid NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction exports and Decrement Bids will be offset in order from the lowest to the highest-priced transactions or bids.

III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)

III.F.2.3.3.1. Eligibility for Credit. All Market Participants that submit pool-scheduled External Transactions (import or export) are eligible for Real-Time External Transaction NCPC Credits, with the exception of External Transactions to wheel energy through the New England Control Area.

III.F.2.3.3.2. Eligible Quantity.

- (a) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that either (i) did not clear in the Day-Ahead Energy Market, or (ii) cleared in the Day-Ahead Energy Market and the price was subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction.
- (b) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that cleared in the Day-Ahead Energy Market and the price was not subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction in excess of the cleared Day-Ahead scheduled transaction amount.

III.F.2.3.3.3. Hourly Offer. The hourly offer for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval offer, which is calculated by multiplying the eligible quantity by the offer price for the interval.

III.F.2.3.3.4. Hourly Revenue. The hourly revenue for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval revenue, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

III.F.2.3.3.5. Hourly Bid. The hourly bid for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval bid, which is calculated by multiplying the eligible quantity by the bid price for the interval.

III.F.2.3.3.6. Hourly Cost. The Real-Time cost for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval cost, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

III.F.2.3.3.7. Credit Calculation. A Real-Time External Transaction NCPC Credit for an External Transaction import for an hour is equal to any portion of the hourly offer in excess of the hourly revenue. A Real-Time External Transaction NCPC Credit for an External Transaction export for an hour is equal to any portion of the hourly cost in excess of the hourly bid.

III.F.2.3.4. [Reserved.]

III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits

III.F.2.3.5.1. Eligibility for Credit. ~~All Market Participants with an Ownership Share in a~~ Resource that is dispatched as a Synchronous Condenser ~~are is~~ eligible for Real-Time Synchronous Condensing NCPC Credits.

III.F.2.3.5.2. Condensing Offer Amount. The condensing offer amount for a Resource is equal to the number of hours that the Resource is dispatched as a Synchronous Condenser in an Operating Day multiplied by the hourly price to condense as specified in the Offer Data for the Resource. For a Resource committed from an offline state to provide synchronous condensing, the condensing offer

amount includes the condensing start-up fee as specified in the Offer Data for the Resource. In the event an hourly price to condense or condensing start-up fee is not included in the Offer Data for the Resource for the hours that the Resource is dispatched as a Synchronous Condenser, the value for the parameter will be zero.

III.F.2.3.5.3. Credit Calculation. The Real-Time Synchronous Condensing NCPC Credit for a Resource for an Operating Day is equal to the condensing offer amount for that Operating Day.

III.F.2.3.6. Cancelled Start NCPC Credits

III.F.2.3.6.1. Eligibility for credit. ~~All Market Participants with an Ownership Share in a Pool-Scheduled Generator Asset or Demand Response Resource~~ ~~are is~~ eligible for a Cancelled Start NCPC Credits if the ISO cancels its commitment of the Pool-Schedule Resource before ~~the a Resource~~ Generator Asset is synchronized to the New England Transmission System, or before a Demand Response Resource has completed its Demand Response Resource Notification Time, except that a Market Participant is not eligible for a credit under the following conditions:

- (a) The start is cancelled before the commencement of the Notification Time or the Demand Response Resource Notification Time;
- (b) The Resource's Notification Time or Demand Response Resource Notification Time as reflected in the Effective Offer is equal to or greater than 24 hours;
- (c) The ~~Resource~~ Generator Asset is synchronized to the New England Transmission System for a Self-Schedule within the period of time equal to the lesser of its Minimum Down Time or 10 hours after receiving the ISO cancelled start order; or
- (d) The ~~Resource~~ Generator Asset fails to meet its scheduled synchronization time and the ISO cancelled start order is issued more than two hours after the Resource's scheduled synchronization time.

III.F.2.3.6.2. Credit Calculation. The Cancelled Start NCPC Credit for a Resource is equal to the Start-Up Fee or Interruption Cost reflected in the Effective Offer multiplied by the percentage of the Notification Time or Demand Response Resource Notification Time, as reflected in the Effective Offer, that the Resource completed prior to the ISO cancelled start order, where:

- (a) The percentage of Notification Time or Demand Response Notification Time completed is equal to the number of minutes after the start of the Notification Time or Demand Response Notification Time the Resource was cancelled divided by the Notification Time or Demand Response Notification Time, and cannot exceed 100%.

III.F.2.3.7. Hourly Shortfall NCPC Credits

III.F.2.3.7.1. Eligibility for Credit. ~~All Market Participants with an Ownership Share in a generating Resource~~ Generator Asset, Demand Response Resource, or DARD Pump that is pool-scheduled in the Day-Ahead Energy Market ~~are is~~ eligible for Hourly Shortfall NCPC Credits for an hour if the ISO (1) cancels its commitment of a non-Fast Start Generator, a non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator; or (2) does not dispatch a Fast Start Generator, a Fast Start Demand Response Resource, a DARD Pump, or a Flexible DNE Dispatchable Generator for the hour; and (3) either the Generator Asset or DARD Pump Resource is offline and available for operation and the generator associated with the DARD Pump is not generating, or the Demand Response Resource has not been dispatched and is available for operation; except that (4) a Market Participant is not eligible for a credit under the following conditions:

- (a) The Resource has been Postured for all or part of the hour;
- (b) The Resource is a Limited Energy Resource that has been Postured during a prior hour in the Operating Day; or
- (c) The Resource is an Intermittent Power Resource that is not a DNE Dispatchable Generator.

III.F.2.3.7.2. Settlement Period. For purposes of calculating Hourly Shortfall NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is eligible for an Hourly Shortfall NCPC Credit. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, ~~or any time a DNE Dispatchable Generator's operating characteristics change~~ to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.

III.F.2.3.7.3. Eligible Quantity. The eligible quantity for each hour of the settlement period is:

- (a) zero for a Fast Start Generator, a Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter, the Start-Up Fee parameter and the No-Load Fee parameter of the Supply Offer, or the total of the energy price parameter and the Interruption Cost of the Demand Reduction Offer, in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market for the hour is greater than the total of the corresponding energy price, Start-Up Fee, No Load Fee, and Interruption Cost parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;
- i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9(~~de~~), the Start-Up Fee, No-Load Fee and energy at the Economic Minimum Limit are equal to \$0, and (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9(~~ef~~), the Start-Up Fee and No-Load Fee are equal to \$0 and the energy at the requested dispatch level is the Energy Price Floor.
- (b) zero for a DARD Pump in the event the energy price parameter in the Demand Bid in the Real-Time Energy Market for the consumption cleared in the Day-Ahead Energy Market for the hour is less than the energy price parameter amount in the Effective Offer-Demand Bid in the Day-Ahead Energy Market for the hour.
- i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9 (~~ed~~), then the energy price at the Minimum Consumption Limit is equal to the Energy Offer Cap, and; (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9 (~~fe~~), then the energy price at the requested dispatch level for DARD Pumps is the Energy Offer Cap.
- (c) the Day-Ahead Economic Minimum Limit or Minimum Reduction for a non-Fast Start Generator, non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter of the Supply Offer or Demand Reduction Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market above the Day-Ahead Economic Minimum Limit or Day-Ahead Minimum Reduction for an hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

and if neither (a) nor (b) nor (c) applies, then;

- (d) the minimum of (i) the amount of energy cleared in the Day-Ahead Energy Market for an hour and (ii) the Resource's Economic Maximum Limit, Maximum Reduction, or a Limited Energy Resource

limit imposed for the hour in the Real-Time Energy Market.

III.F.2.3.7.4. Credit Calculation (for non-Fast Start Generators, non-Fast Start Demand Response Resources, non-DARD Pumps and non-Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC Credit for a Resource, other than a Fast Start Generator, a Fast Start Demand Response Resource, a DARD Pump, or a Flexible DNE Dispatchable Generator, adjusted as described in III.F.1(h), is equal to:

(a) the greater of (i) zero and (ii) the total of (the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the Day-Ahead Economic Minimum Limit for the hour or the Day-Ahead Minimum Reduction for the hour) for all hours of the settlement period,

plus

(b) for each hour of the settlement period, for Generator Assets, the greater of (i) zero and (ii) the product of (1) the Real-Time Price minus the Day-Ahead Price for an hour and (2), ~~multiplied by~~ the eligible quantity minus the Day-Ahead Economic Minimum Limit for the hour; or, for Demand Response Resources, the greater of (i) zero and (ii) the product of (1) the Real Time Price minus the Day-Ahead Price for an hour and (2) the eligible quantity minus the Day-Ahead Minimum Reduction for the hour.

III.F.2.3.7.5. Credit Calculation (for Fast Start Generators, Fast Start Demand Response Resources and Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC Credit for a Fast Start Generator, Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and (ii) the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the eligible quantity for the hour, adjusted as described in III.F.1(h).

III.F.2.3.7.6 Credit Calculation (for DARD Pumps). The Hourly Shortfall NCPC Credit for a DARD Pump is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the Day-Ahead Price minus the Real-Time Price for an hour, multiplied by the eligible quantity for the hour.

III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability

III.F.2.3.8.1. Eligibility for Credit. ~~All Market Participants with an Ownership Share in a~~ Limited Energy Resource ~~are~~ is eligible for real-time posturing NCPC credits for any Operating Day during which the Resource has been Postured, when a request to minimize the as-bid production costs of the Resource has been submitted. For purposes of calculating real-time posturing NCPC credits, the Resource is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator. If the Resource is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

III.F.2.3.8.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits for Limited Energy Resources, a settlement period is the period of one or more contiguous hours from the initiation of Posturing through the end of the Operating Day.

III.F.2.3.8.3 Resources Sharing a Single Fuel Source. When Limited Energy Resources that share a fuel source are Postured, for purposes of calculating real-time posturing NCPC credits the energy available to the Postured Resources will be allocated among the Postured Resources sharing the fuel source as indicated by estimates of available energy provided by the Lead Market Participant for each Resource prior to Posturing.

III.F.2.3.8.4. Estimated Replacement Cost of Energy. The estimated replacement cost of energy is (i) the average of the Day-Ahead Prices for hours ending 3 through 5 in the subsequent Operating Day for pumped storage generators, or (ii) the product of the oil index price multiplied by the oil-fired generator proxy heat rate for fuel oil-fired generators, or (iii) zero for Resources other than pumped storage generators and fuel oil-fired generators.

For fuel oil-fired generators, the oil index price is the ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation, and the oil-fired generator proxy heat rate is the average of the heat rate at Economic Min and the heat rate at Economic Max, where the heat rate at Economic Min is, for a Resource, the average hourly energy price parameter of the Supply Offer at the Resource's Economic Minimum Limit at the time of the Posturing decision divided by the oil index price, and the heat rate at Economic Max is, for a Resource, the average hourly energy price parameter of the Supply Offer at the Resource's Economic Maximum Limit at the time of the Posturing decision divided by the oil index price.

III.F.2.3.8.5. Estimated Revenue. The estimated revenue for a Resource is the optimized energy output multiplied by the Real-Time Price for all hours in the settlement period. The optimized energy output is estimated for each hour by allocating the Postured energy to hours that the Resource would have operated had it not been Postured based on Real-Time Prices in the Operating Day, subject to the following conditions:

- (a) the optimized energy output determination will take account of the Resource's Economic Minimum Limit, and Economic Maximum Limit.
- (b) the optimized energy output determination will take account of the estimated avoided cost of replacing energy that is not allocated to any hour and remains available at the end of the Operating Day.
- (c) for non-Fast Start Generators, the optimized energy output is calculated for the contiguous hours from the time the Resource is Postured until the available energy is depleted.

III.F.2.3.8.6. Estimated Avoided Replacement Cost. The estimated avoided replacement cost for an Operating Day is the remaining energy that would have been available at the end of the Operating Day had the Resource operated in accordance with the optimized energy output determination in Section III.F.2.3.8.5, plus any increase in the remaining energy resulting from pumping during the Operating Day after the Resource is Postured, multiplied by the estimated replacement cost of energy.

III.F.2.3.8.7. Actual Revenue. The actual revenue for a Resource is the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the settlement period.

III.F.2.3.8.8. Actual Avoided Replacement Cost. The actual avoided replacement cost for an Operating Day is the actual remaining energy at the end of the Operating Day multiplied by the estimated replacement cost of energy.

III.F.2.3.8.9. Credit Calculation. The real-time posturing NCPC credit for Limited Energy Resources is equal to the greater of (i) zero and (ii) the estimated revenue plus the estimated avoided replacement cost, minus the actual revenue plus the actual avoided replacement cost.

III.F.2.3.9. Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured for Reliability and for Demand Response Resources Postured for Reliability

III.F.2.3.9.1. Eligibility for Credit. ~~All Market Participants with an Ownership Share in a generating Resource Generator Assets; (other than a Limited Energy Resources); and Demand Response Resources~~ are eligible for real-time posturing NCPC credits for the hours during which the Resource has been Postured.

III.F.2.3.9.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits, a settlement period is an hour during which the ~~generating Generator Asset or Demand Response~~ Resource is Postured.

III.F.2.3.9.3. Offer Used for Estimated Hourly Revenue and Cost.

~~(a) For a Generator Asset, purposes of calculating real-time posturing NCPC credits,~~ the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:

~~(i)~~ Energy Price: the higher of the energy price parameter specified in ~~(#1)~~ (1) the Supply Offer for the hour at the time the ISO Postures the Resource, or ~~(#2)~~ (2) the Supply Offer for the hour at the start of the hour;

~~(ii)~~ Start-Up Fee and No Load Fee: for Resources Postured offline, the Start-Up Fee and No-Load Fee specified in the Supply Offer for the hour at the time the Resource is Postured;

~~(iii)~~ for Resources Postured to remain online but reduce output, the Start-Up Fee and No-Load Fee are calculated pursuant to Section III.F.2.2.2.3.

~~(b) For a Demand Response Resource, the offer parameters used to estimate revenue and cost for an hour~~ for purposes of calculating real-time posturing NCPC credits are:

~~(i)~~ Energy Price: the higher of the energy price parameter specified in (1) the Demand Reduction Offer for the hour at the time the ISO Postures the Resource, or (2) the Demand Reduction Offer for the hour at the start of the hour;

~~(ii)~~ Interruption Cost: for a Demand Response Resource Postured to a demand reduction of zero MWs, the Interruption Cost specified in the Demand Reduction Offer for the hour at the time the Demand Response Resource is Postured; for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MWs, the Interruption Cost is calculated pursuant to Section III.F.2.2.2.3.

III.F.2.3.9.4. Estimated Hourly Revenue.

(a) The estimated hourly revenue for a Generator Asset Resource is the optimized energy output multiplied by the Real-Time Price for the hour. The optimized energy output is estimated for each hour by determining where the Resource would have operated had it not been Postured based on Real-Time Prices. -The optimized energy output determination will take account of the energy price parameter of the Supply Offer and the Resource's Economic Minimum Limit and Economic Maximum Limit.

(b) The estimated hourly revenue for a Demand Response Resource is the optimized demand reduction multiplied by the Real-Time Price for the hour, where:

(i) The optimized demand reduction is estimated for each hour by determining where the Demand Response Resource would have operated had it not been Postured based on Real-Time Prices. The optimized demand reduction determination will take account of the energy price parameter of the Demand Reduction Offer and the Demand Response Resource's Minimum Reduction and Maximum Reduction.

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III.F.2.3.9.5. Estimated Hourly Cost.

(a) The estimated hourly cost for a Generator Asset Resource is the energy price parameter of the Supply Offer for the optimized energy output for the hour, plus the Start-Up Fee and the No-Load Fee, subject to the following conditions:

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(i) For a Fast Start Generator Postured offline, the Start-Up Fee is included in each hour's cost and is not subject to apportionment:-

(ii) For a non-Fast Start Generator Postured offline, the Start-Up Fee is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.

(b) The estimated hourly cost for a Demand Response Resource is the energy price parameter of the Demand Reduction Offer for the optimized demand reduction for the hour (where optimized demand reduction is determined pursuant to Section III.F.2.3.9.4(b)), plus the Interruption Cost, subject to the following conditions:

(i) For a Fast Start Demand Response Resource Postured to a demand reduction level of zero MWs, the Interruption Cost is included in each hour's cost and is not subject to apportionment:

(ii) For a non-Fast Start Demand Response Resource Postured to a demand reduction of greater than zero MWs, the Interruption Cost is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.

(c) A Generator Asset is treated as a Fast Start Generator and a Demand Response Resource is treated as a Fast Start Demand Response Resource For purposes of determining the estimated hourly cost ~~for a Resource, the Resource is treated as a Fast Start Generator~~ only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator or non-Fast Start Demand Response Resource. If at the time the Resource is offline at the time it is Postured the Generator Asset is offline, or the Demand Response Resource has not been dispatched, then its designation as a Fast Start Generator or ~~non-Fast Start Generator~~ Demand Response Resource is determined as of the time of the Posturing decision.

III.F.2.3.9.6. Actual Hourly Revenue. The actual hourly revenue for a Generator Asset or a Demand Response Resource is the sum of the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the hour.

III.F.2.3.9.7. Actual Hourly Cost.

(a) The actual hourly cost for a Resource Postured to remain online but reduce output is the sum of the interval cost, which is the energy price parameter of the Supply Offer for the Metered Quantity For Settlement for the interval, plus the Start-Up Fee and No-Load Fee calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Resource Postured offline is zero.

~~(b)~~ The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MWs is the sum of the interval cost, which is the energy price parameter of the Demand Reduction Offer for the Metered Quantity For Settlement for the interval, plus the Interruption Cost calculated pursuant to pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to zero MWs is zero.

III.F.2.3.9.8. Credit Calculation. The real-time posturing NCPC credit for a ~~Generator Asset~~ Asset (other than a Limited Energy Resource); or a Demand Response Resource is equal to the greater of (i) zero and (ii) the estimated hourly revenue minus the estimated hourly cost, minus the actual hourly revenue minus actual hourly cost, adjusted as described in III.F.1(h).

III.F.2.3.10. Rapid Response Pricing Opportunity Cost NCPC Credits Resulting from Commitment of Rapid Response Pricing Assets

III.F.2.3.10.1. Eligibility for Credit. During any five-minute pricing interval in which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, ~~all Market Participants with an Ownership Share in any~~ Resource that is committed and able to respond to Dispatch Instructions during the interval ~~are is~~ eligible to receive a Rapid Response Pricing Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Resource is non-dispatchable; the Resource has been Postured or has provided Regulation at any time during the hour in which the interval occurs; ~~or~~ if the Resource is a Settlement Only Resource, ~~a Demand Response Resource,~~ or if the Resource is an External Resource or External Transaction.

III.F.2.3.10.2. Economic Net Revenue or Economic Net Benefit.

(a) The economic net revenue for a ~~Resource other than a Dispatchable Asset Related Demand Generator Asset or Demand Response Resource~~ during the pricing interval is the Resource's optimized feasible energy quantity multiplied by the Real-Time Price, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

(b) The economic net benefit for a Dispatchable Asset Related Demand during the pricing interval is the Resource's energy price parameter for its optimized feasible energy quantity as reflected in its Demand Bid, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the optimized feasible energy quantity multiplied by the Real-Time Price.

(c) The optimized feasible energy and reserve quantities are determined consistent with the Resource's offer or bid parameters, and are the energy and reserve quantities that maximize the Resource's economic net revenue or economic net benefit for the pricing interval, without changing the Resource's commitment status.

III.F.2.3.10.3. Actual Net Revenue or Actual Net Benefit.

(a) The actual net revenue for a ~~Resource other than a Dispatchable Asset Related Demand Generator Asset or Demand Response Resource~~ is the greater of: (i) the actual energy quantity supplied during the pricing interval multiplied by the Real-Time Price, plus the actual reserve quantity supplied during the pricing interval multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities; and (ii) the dispatched energy quantity multiplied by the Real-Time Price, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

(b) The actual net benefit for a Dispatchable Asset Related Demand is the greater of: (i) the energy price parameter for the actual energy quantity consumed as reflected in the Demand Bid, plus the actual reserve quantity supplied by the Real-Time Reserve Clearing Price, minus the actual

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energy quantity consumed multiplied by the Real-Time Price, and (ii) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.

III.F.2.3.10.4. Credit Calculation. The real-time Rapid Response Pricing Opportunity Cost NCPC Credit for a Resource is equal to the greater of: (i) zero; and (ii) the Resource's economic net revenue or economic net benefit for the interval less its actual net revenue or actual net benefit for the pricing interval.

III.F.2.4. Apportionment of NCPC Credits. For purposes of this Section III.F.2.4, any values previously established at the five minute level shall be aggregated to create hourly values.

Each of the Day-Ahead Energy Market NCPC Credits for a non-Fast Start Generator, a non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator are apportioned to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue for all hours in the settlement period.

Each of the Real-Time Commitment NCPC Credits is apportioned as follows: (i) for the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the portion of the Commitment Period, and (ii) for all remaining intervals of the settlement period, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the period.

Each of the Hourly Shortfall NCPC Credits for a non-Fast Start Generator, a non-Fast Start Demand Response Resource or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator for energy cleared in the Day-Ahead Energy Market at the Resource's Economic Minimum Limit or Minimum Reduction is apportioned to the hours in which the Real-Time Price exceeds the Day-Ahead Price, for all hours in the settlement period.

The following NCPC credits are assigned to the hours for which the credit was calculated:

- Day-Ahead Energy Market NCPC Credits for Fast Start Generators, Fast Start Demand Response Resources, DARD Pumps, and Flexible DNE Dispatchable Generators, where

the daily starts in their Day-Ahead Energy Market schedules are fewer than their Maximum Number of Daily Starts.

- Real-Time Dispatch Lost Opportunity Cost NCPC Credits,
- Real-Time Dispatch NCPC Credits for all Resources,
- Day-Ahead External Transaction Import and Increment Offer NCPC Credits,
- Day-Ahead External Transaction Export and Decrement Bid NCPC Credits,
- Real-Time External Transaction NCPC Credits,
- Hourly Shortfall NCPC Credits for Fast Start Generators, [Fast Start Demand Response Resources](#), DARD Pumps and Flexible DNE Dispatchable Generators,
- Hourly Shortfall NCPC Credits for non-Fast Start Generators, [non-Fast Start Demand Response Resources](#), and DNE Dispatchable Generators that are not Flexible DNE Dispatchable Generators for energy cleared in the Day-Ahead Energy Market above the Resource's Economic Minimum Limit [or Minimum Reduction](#), and
- Rapid Response Pricing Opportunity Cost NCPC Credits as described in Section III.F.2.3.10.

III.F.2.5. NCPC Credit Designation for Purposes of NCPC Cost Allocation. Each hourly credit for Day-Ahead Energy Market NCPC Credits, Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, Day-Ahead External Transaction Import and Increment Offer NCPC Credits, Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, Real-Time External Transaction NCPC Credits, Hourly Shortfall NCPC Credits, and Real-Time Posturing NCPC Credits for Generator [Assets](#) (Other Than Limited Energy Resources) [Postured For Reliability and Demand Response Resources](#) Postured For Reliability, and each daily credit for Real-Time Synchronous Condensing NCPC Credits, Cancelled Start NCPC Credits, Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability, and Rapid Response Pricing Opportunity Cost NCPC Credit is designated as first contingency, second contingency, voltage (VAR), distribution (SCR), ISO initiated audits and Minimum Generation Emergency consistent with the reason provided by the ISO when issuing a Dispatch Instruction for the Resource. If there is more than one reason provided by the ISO when issuing the Dispatch Instruction, the NCPC Credits are divided equally for purposes of the above designations. With the exception of Day-Ahead External Transaction Import and Increment Offer NCPC Credits and Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, the hourly credits are summed to determine the total credits for each NCPC Charge category for a day.

III.F.3. Charges for NCPC

III.F.3.1. Cost Allocation.

III.F.3.1.1 Day-Ahead Energy Market NCPC Cost Allocation. NCPC costs for the Day-Ahead Energy Market are allocated and charged as follows:

- (a) The total NCPC cost for the Day-Ahead Energy Market associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.
- (b) The total NCPC cost for the Day-Ahead Energy Market for resources designated as Special Constraint Resources in the Day-Ahead Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.
- (c) The total NCPC cost for the Day-Ahead Energy Market for resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.
- (d) For each External Node, the total NCPC cost for Day-Ahead External Transaction Import and Increment Offer NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Load Obligations at the External Node for the hour.
- (e) For each External Node, the total Day-Ahead External Transaction Export and Decrement Bid NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Generation Obligations at the External Node for the hour.
- f) All remaining NCPC costs for the Day-Ahead Energy Market (except the NCPC costs for DARD Pumps) are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub).
- g) All remaining NCPC costs for the Day-Ahead Energy Market associated with DARD Pumps are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub) excluding Day-Ahead Load Obligations associated with DARD Pumps.

III.F.3.1.2. Real-Time Energy Market NCPC Cost Allocation. NCPC costs for the Real-Time Energy Market are allocated and charged as follows, subject to the conditions in Section III.F.3.1.3:

- (a) The total NCPC cost for the Real-Time Energy Market associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are allocated and charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.
- (b) The total NCPC cost for the Real-Time Energy Market for resources designated as Special Constraint Resources in the Real-Time Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.
- (c) The total ISO initiated audit NCPC cost for resources performing an ISO initiated audit is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with DARD Pumps.
- (d) The total NCPC cost for resources ~~following Dispatch Instructions while~~ being postured in the Real-Time Energy Market is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with DARD Pumps.
- (e) The total NCPC cost for Rapid Response Pricing Opportunity Cost NCPC Credit during pricing intervals in which one or more Rapid Response Pricing Asset is committed in the Real-Time Energy Market (and not Self-Scheduled) is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with DARD Pumps.
- (f) The total NCPC cost for the Real-Time Energy Market for resources identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.
- (g) Total Minimum Generation Emergency Credits within a Reliability Region are allocated and charged hourly to Market Participants based on each Market Participant's pro rata share of Real-Time Generation Obligations, and positive Real-Time Demand Reduction Obligations, excluding that portion of a Market Participant's Real-Time Generation Obligation and Real-Time Demand Reduction Obligation within a Reliability Region that is eligible for a Real-Time Dispatch NCPC Credit pursuant to Section III.F.2.2.3 during a Minimum Generation Emergency.
- (h) The total NCPC cost for Real-Time Dispatch Lost Opportunity Cost NCPC Credits is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with DARD Pumps.
- (i) All remaining NCPC costs for the Real-Time Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of the absolute values of a Market

Participant's (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day (excluding certain positive Real-Time Load Obligation Deviations as described in Section III.F.3.1.3(d)); (ii) generation deviations for Pool-Scheduled Resources not following Dispatch Instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following Dispatch Instructions, and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following Dispatch Instructions, including External Resources, in MWhs during the Operating Day; (iii) demand reduction deviations for Pool-Scheduled Demand Response Resources not following Dispatch Instructions; and (iv#) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day. The Real-Time deviations calculation is specified in greater detail in Section III.F.3.2.

III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation.

- (a) If a ~~generation resource~~ Generator Asset has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.
- (b) If a Demand Response Resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the resource should not be dispatched in order to avoid a Minimum Generation Emergency, the Market Participant will be responsible for all Real-Time Demand Reduction Obligation Deviation charges, but will not incur related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.
- (c) Any difference between the actual consumption (Real-Time Load Obligation) of Dispatchable Asset Related Demands ~~Resources~~ and Dispatchable Asset Related Demand bids that clear in the Day-Ahead Energy Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation for the purpose of allocating costs for Real-Time Energy Market NCPC Credits.
- ~~(b)~~(d) In any hour during which a Capacity Scarcity Condition occurs or ISO New England Operating Procedure No. 4 or ISO New England Operating Procedure No. 7 are implemented, any NCPC Charges that would have been allocated pursuant to Section III.F.3.2 to net positive Real-Time Load Obligation Deviations in an affected Load Zone (and related portion of adjacent External Nodes) are instead allocated and charged to Market Participants based on their pro rata share of the sum of their Real-Time Load Obligation (excluding Real-Time Load Obligations associated with a Postured

Dispatchable Asset Related Demand Resource) in all the affected Load Zones and (and related portion of adjacent External Nodes) during the affected hour(s). For purposes of this calculation, the ISO shall apportion any Real-Time Load Obligations and Real-Time Load Obligation Deviations at an External Node equally among the Load Zones to which the External Node is interconnected.

III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits.

Each Market Participant's pro-rata share of the Real-Time deviations for Real-Time Energy Market NCPC Credits is the following:

- (a) For each Self-Scheduled Generator Asset, If the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

- (b) For each Self-Scheduled Generator Asset, If the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) or (Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

- (c) For each Self-Scheduled Generator Asset, If the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

plus,

(d) for each Pool Scheduled ~~Generator Asset~~~~generating Resource~~:

- (i) If the ~~Resource~~~~Generator Asset~~ is not following Dispatch Instructions, ~~and~~ has cleared Day-Ahead, ~~and~~ has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – Desired Dispatch Point) for each ~~generating Resource~~~~Generator Asset~~.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

- (ii) If the ~~Resource~~~~Generator Asset~~ is not following Dispatch Instructions, has cleared Day-Ahead, ~~that~~ has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – cleared Day-Ahead MWh) for each ~~generating Resource~~~~Generator Asset~~.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(e) for each Pool Scheduled Demand Response Resource:

- (i) If the Demand Response Resource is being dispatched, is not following Dispatch Instructions, has cleared Day-Ahead, and has not been ordered to stop reducing demand for reliability purposes: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction – Desired Dispatch Point) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Demand Response Resource is unavailable and has cleared Day-Ahead: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction – cleared Day-Ahead MWh) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

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plus,

(fe) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation ~~the sum of the hourly~~,

where

- (i) each Market Participant's Real-Time Load Obligation Deviation for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub), and
- (ii) for purposes of calculating a Participant's Real-Time Load Obligation Deviation under this subsection (e), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and
- (iii) External Transaction sales curtailed by the ISO are omitted from this calculation.

plus,

(gf) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation,

Where

- (i) each Market Participant's Real-Time Generation Obligation Deviation at External Nodes for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes, and
- (ii) for purposes of calculating a Participant's Real-Time Generation Obligation Deviation under this sub-section (f), a Day-Ahead External Transaction that is not associated with a Real-Time

External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and

(iii) External Transaction purchases curtailed by the ISO are omitted from this calculation.

plus,

(h) the absolute value of the total over all Locations of the Market Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

III.F.3.3 Local Second Contingency Protection Resource NCPC Charges.

Each Market Participant's pro-rata share of the cost for Day-Ahead Energy Market NCPC Credits and Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection is based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region, excluding Real-Time Load Obligations associated with DARD Pumps subject to the following conditions:

- (a) The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating a Market Participant's pro-rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.
- (b) For hours in which there is an NCPC cost for a resource providing Local Second Contingency Protection and ISO is selling Emergency eEnergy to an adjacent Control Area, the scheduled amount of Emergency eEnergy at the applicable External Node will be included in the calculation of a Market Participant's pro rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection as if the Emergency eEnergy sale were a Real-Time Load Obligation within each affected Reliability Region. The pro rata share calculated for

the Emergency Energy Transaction shall be included in the charges under an agreement for purchase and sale of Emergency Energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency Energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

External Node Common Name	Associated Transmission Facilities	Reliability Region(s)	Allocator
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390/3016) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-7 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line) Alps – Berkshire Line (393Line) Pleasant Valley – Long Mountain Line (398 Line)	Vermont, Vermont Vermont West Central Massachusetts West Central Massachusetts Connecticut	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
NY NNC External Node	Northport-Norwalk Harbor (601,602 and 603 Lines)	Connecticut	100% to Connecticut
NY CSC External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(c) For each month, the ISO performs an evaluation of total Local Second Contingency Protection Resource NCPC Charges for each Reliability Region. If, for any Reliability Region, the magnitude

of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph c, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency eEnergy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a DARD Pump.

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge $_{(Reliability\ Region, month)}$ $>$.06 X Load Weighted Real-Time LMP $_{(Reliability\ Region, month)}$

Condition 2 – is the Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region, month)}$ $>$ 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region)}$

Where:

Real-Time Load Obligation $_{(Reliability\ Region, month)}$ equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge $_{(Reliability\ Region, month)}$ equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation $_{(Reliability\ Region, month)}$.

Load Weighted Real-Time LMP $_{(Reliability\ Region, month)}$ equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation $_{(Reliability\ Region, month)}$.

Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region, month)}$ equals the Local Second Contingency Protection Resource Charge $_{(Reliability\ Region, month)}$ divided by the Load Weighted Real-Time LMP $_{(Reliability\ Region, month)}$.

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge %
 (Reliability Region) equals the sum of the prior 12 months' values, not including the current month, of
 Local Second Contingency Protection Resource Charge % (Reliability Region, month) divided by 12. (For
 the purposes of other calculations which include the Twelve Month Rolling Average Local
 Second Contingency Protection Resource Charge % (Reliability Region), a value of .001 will be
 substituted for any Twelve Month Rolling Average Local Second Contingency Protection
 Resource Charge % (Reliability Region) value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection
 Resource Charge (Reliability Region, month) is triggered.

- (ii) Determination of the portion of Local Second Contingency Protection Resource Charge (Reliability
 Region, month) to be reallocated –

Local Second Contingency Protection Resource Charge (Reliability Region, month) to be reallocated =
 Real-Time Load Obligation (Reliability Region, month) X Min (Condition 1 Rate (Reliability Region, month),
 Condition 2 Rate (Reliability Region, month))

Where:

Condition 1 Rate (Reliability Region, month) equals the Local Second Contingency Protection Resource
 Charge (Reliability Region, month) minus .06 times the Load Weighted Real-Time LMP (Reliability Region, month).

Condition 2 Rate (Reliability Region, month) equals the Local Second Contingency Protection Resource
 Charge (Reliability Region, month) minus 2 times the Twelve Month Rolling Average Local Second
 Contingency Protection Resource Charge % (Reliability Region) times the Load Weighted Real-Time
 LMP (Reliability Region, month).

- (iii) Determination of Local Second Contingency Protection Resource Charge (Reliability Region, month)
 reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

$(\text{Real-Time Load Obligation}_{(\text{Participant, Reliability Region, month})} / \text{Real-Time Load Obligation}_{(\text{Reliability Region, month})}) * \text{Local Second Contingency Protection Resource Charges}_{(\text{Reliability Region, month})}$ to be reallocated

Where:

$\text{Real-Time Load Obligation}_{(\text{Participant, Reliability Region, month})}$ equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

$(\text{Regional Network Load}_{(\text{Transmission Customer, Reliability Region, month})} / \text{Regional Network Load}_{(\text{Reliability Region, month})}) * \text{Local Second Contingency Protection Resource Charges}_{(\text{Reliability Region, month})}$ to be reallocated

Where:

$\text{Regional Network Load}_{(\text{Reliability Region, month})}$ equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

$\text{Regional Network Load}_{(\text{Customer, Reliability Region, month})}$ equals:

The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

I.2 Rules of Construction; Definitions

I.2.1 Rules of Construction:

In this Tariff, unless otherwise provided herein:

- (a) words denoting the singular include the plural and vice versa;
- (b) words denoting a gender include all genders;
- (c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;
- (d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;
- (e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;
- (f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;
- (g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;
- (h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;
- (i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;
- (j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

other late payment or charge, provided such payment is made on such next succeeding Business Day);

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

I.2.2. Definitions:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

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

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

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

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

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

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

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

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

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Dispatchable Asset Related Demand, or a 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 costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

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

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

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

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

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

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

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a 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 On-Peak Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

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

Average Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

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

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

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

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 (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

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

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

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

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

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

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through 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, as described in Section III.13.7.2.3 of Market Rule 1.

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

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

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

Capacity 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.13.7.5.1 of Market Rule 1.

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

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

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

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

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

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

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

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

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

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

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

Capacity Requirement is described in Section III.13.7.5.1 of Market Rule 1.

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

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

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

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

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

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

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

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

Category 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 or the demand reduction capability of a Demand Response Resource.

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 the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

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

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and 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.8.1.1. 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.8.2.

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

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

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

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

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

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

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, 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 Response Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch 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.12.4A.

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.

DARD Pump is a Dispatchable Asset Related Demand that consists of all or part of the pumping load of a pumped storage generating Resource 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) is available for dispatch and manned or has automatic remote dispatch capability, and; (iv) is capable of receiving a start-up or shutdown Dispatch Instruction electronically.

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

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

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

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

Distributed Generation means generation 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 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 Capacity Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

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

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

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

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

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

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

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

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

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

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

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

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent

fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

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

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

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

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

Effective Offer is the set of Supply Offer values (or **Demand Bid values** in the case of DARD Pumps) that are used for NCPC calculation purposes as specified in Section III.F.1.a.

EFT is electronic funds transfer.

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

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

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

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

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

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

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

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

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

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

EMS is energy management system.

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

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

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

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

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

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

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

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

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

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

Energy Offer Floor is negative \$150/MWh.

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

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.

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

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

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

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, 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 Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Fast Start Generator means a 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; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Forward Capacity Auction (FCA) is the annual 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 \$9,000/megawatt-month.

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

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

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

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

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

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

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

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

Hourly PER is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Intermittent Settlement Only Resource is a Settlement Only Resource that is also an Intermittent Power Resource.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

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.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means 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 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 Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA.

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade or a Public Policy Transmission Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any

Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart CIP Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC

System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is 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.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a DARD Pump is expected to be able to consume in the next Operating Day.

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 Demand Response 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 Demand Response Asset comprised of Distributed Generation.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that 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.

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 Number of Daily Starts is the maximum number of times that a DARD Pump or a generating Resource can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time an On-Peak Demand Resource or Seasonal Peak Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Resources or Seasonal Peak Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Resources or Seasonal Peak Demand Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MG TSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MG TSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is 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 or DARD Pump has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or DARD Pump can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources to operate at or below Economic Minimum Limit, in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a DARD Pump has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of 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.13.7.5 of Market Rule 1.

Net Supply is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46

and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.1 of Market Rule 1.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

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.13.7.5.1.3.

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-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource .

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. “Non-Incumbent Transmission Developer” also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-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-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and 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.

On-Peak Demand Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a 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.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.1.2 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.1.2.1 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The “Phase I Transfer Capability” is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any

effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability.

Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point

Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is a Fast Start Generator, a Flexible DNE Dispatchable Generator, or a Dispatchable Asset Related Demand for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Run Time does not exceed one hour; and (ii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

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) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a 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) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning

studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTTSA holder that sells, assigns or transfers its rights under its MGTTSA, 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, an External Transaction or Demand Response Resource. For purposes of providing Regulation, Resource means a generating unit, a Dispatchable Asset Related Demand or an Alternative Technology Regulation Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured

to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission’s corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a 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 Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Self-Schedule is the action of a Market Participant in committing or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing or scheduling a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been scheduled or dispatched by the ISO to provide the Energy. For a Dispatchable Asset Related Demand, Self-Schedule is the action of a Market Participant in committing or scheduling a Dispatchable Asset Related Demand to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the Dispatchable Asset Related Demand would have been scheduled or dispatched by the ISO to consume Energy. Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to: (i) a Generator Asset's Economic Minimum Limit; (ii) a Dispatchable Asset Related Demand's Minimum Consumption Limit.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours.

However, if the Resource has at least one hour of the day with a unit status of “available,” the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer’s Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity’s assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any

matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock; (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of (1) a generating Resource that can be converted fully into energy within ten minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of (1) a generating Resource that is electrically synchronized to the New England Transmission System that can be converted fully into energy within ten minutes from the request of the ISO; (2) a Dispatchable Asset Related Demand pump that is electrically synchronized to the New England Transmission System that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO; or (3) a Demand Response Resource that has been dispatched that can provide demand reduction within ten minutes from the request of the ISO for which none of the associated Demand Response Assets have a generator whose output can be controlled located behind the Retail Delivery Point other than emergency generators that cannot operate electrically synchronized to the New England Transmission System.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) means the reserve capability of (1) a generating Resource that can be converted fully into energy within thirty minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within thirty minutes from the request of the ISO.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart O&M Payment is the annual compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total 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 On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project

specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual 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 pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2(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.

I.3 Obligations of Market Participants and Other Customers

The ISO acts as Counterparty for sales to its Customers of Regional Transmission Service, and for agreements and transactions with its Customers, including but not limited to assignments involving Customers, and agreements and transactions with Customers involving sale to the ISO and/or purchase from the ISO of energy, capacity, reserves, regulation, Ancillary Services, FTRs and involving other products, service and transactions, all as specified in Sections II and III of the Tariff (collectively, the “Products”).

To the extent permitted by applicable law, any warranties provided by the sellers or assignors to the ISO of the Products which cover the Products, whether express or implied, are hereby passed to the Customers on a “pass through basis” and to the extent not passed through, any such warranties are hereby assigned by ISO to Customers. Sellers and assignors to the ISO and Customers acknowledge that warranties on such Products are limited to that offered by the seller or assignor to the ISO and will exist, if at all, solely between the seller or assignor to the ISO and the Customer. AS BETWEEN CUSTOMER AND ISO AS COUNTERPARTY, NO EXPRESS OR IMPLIED WARRANTIES ARE MADE BY THE ISO REGARDING THE PRODUCTS SOLD BY THE ISO AS COUNTERPARTY, AND ANY SUCH PRODUCTS ARE PROVIDED ON AN “AS IS” AND “AS AVAILABLE” BASIS. THE ISO MAKES NO WARRANTY OR REPRESENTATION THAT THE PRODUCTS WILL BE UNINTERRUPTED OR ERROR FREE. THE CUSTOMER HEREBY WAIVES, AND THE ISO HEREBY DISCLAIMS, ALL OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING, WITHOUT LIMITATION, ANY WARRANTY OF MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, TITLE AND NON-INFRINGEMENT. THE ISO DOES NOT WARRANT THAT THE PRODUCTS OFFERED WILL MEET CUSTOMER’S REQUIREMENTS. NO ORAL OR WRITTEN INFORMATION OR ADVICE GIVEN BY THE ISO OR ANY AUTHORIZED REPRESENTATIVE OF THE ISO SHALL CREATE A WARRANTY OR IN ANY WAY INCREASE THE SCOPE OF ANY PASS THROUGH OR ASSIGNED WARRANTY. SOME JURISDICTIONS DO NOT ALLOW THE EXCLUSION OF IMPLIED WARRANTIES IN CERTAIN CIRCUMSTANCES, SO THE ABOVE EXCLUSION APPLIES ONLY TO THE EXTENT PERMITTED BY APPLICABLE LAW.

I.3.1. Service Agreement:

Receipt of service under this Tariff requires the execution of a Market Participant Service Agreement in the form specified in Attachment A or Attachment A-1, as applicable, to this Tariff unless the Customer seeks transmission service only and does not participate in the New England Markets (in which case the Customer must execute a Transmission Service Agreement). Receipt of Local Service under Section II of

this Tariff requires the execution of a Transmission Service Agreement in the form specified in Attachment A to Schedule 21 of Section II of this Tariff for Local Service and shall be subject to the requirements of Schedule 21. Receipt of OTF Service under Section II of this Tariff requires the execution of a Transmission Service Agreement in the appropriate form specified under Schedule 20 of Section II of this Tariff and shall be subject to the requirements of Schedule 20.

I.3.2. Assets:

Each Market Participant shall, to the fullest extent practicable, cause all of the Assets it owns or operates to be designed, constructed, maintained and operated in accordance with Good Utility Practice and the provisions of this Tariff, the ISO New England Operating Procedures, and the ISO New England Planning Procedures.

I.3.3. Maintenance and Repair:

Each Market Participant shall, to the fullest extent practicable: (a) cause Assets owned or operated by it to be withdrawn from operation for maintenance and repair only in accordance with maintenance schedules reported to, and approved and published by the ISO in accordance with the ISO New England Operating Procedures, (b) restore such Assets to good operating condition with reasonable promptness, and (c) in emergency situations, accelerate maintenance and repair at the reasonable request of the ISO in accordance with the ISO New England Planning Procedures.

I.3.4. Central Dispatch:

Each Market Participant shall, to the fullest extent practicable, subject each of the Assets it owns or operates to central dispatch by the ISO; provided, however, that each Market Participant shall at all times be the sole judge as to whether or not and to what extent safety requires that at any time any of such facilities will be operated at less than their full capacity.

I.3.5. Provision of Information:

The Customers shall provide the ISO with any and all information within their custody or control that the ISO deems necessary to perform its obligations under this Tariff, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. Each Customer shall ensure that the ISO has an accurate list of the Customer's Affiliates. The ISO will compile a list that shall be considered definitive. It will be the Customer's responsibility to regularly review the list and to promptly (and in advance of Affiliate changes, where possible) provide the ISO with additions and/or corrections to the list and, when requested, relevant supporting documentation.

I.3.6. Records and Information:

Each Customer shall keep such records as may reasonably be required by the ISO, and shall furnish to the ISO such records, reports and information (including forecasts) as it may reasonably require, provided that confidentiality thereof is protected in accordance with the ISO New England Information Policy.

I.3.7. Payment of Invoices; Compliance with Policies:

Each Customer is obligated to pay when due in accordance with this Tariff, the ISO New England Financial Assurance Policy and the ISO New England Billing Policy all amounts invoiced to it pursuant to this Tariff, and to comply with those terms, conditions and policies in all respects. If a Customer fails to meet the requirements specified in the ISO New England Financial Assurance Policy and ISO New England Billing Policy, the ISO may take such actions as are specified in those policies.

I.3.8. Protective Devices for Transmission Facilities:

Each Market Participant shall install, maintain and operate such protective equipment and switching, voltage control, load shedding and emergency facilities as the ISO and the applicable Transmission Owner may determine to be required in order to assure continuity of service and the stability of the New England Transmission System.

I.3.9. Review of Market Participant's Proposed Plans:**I.3.9.1 Submission and Review of Proposed Plan Applications:**

Each Market Participant and Transmission Owner shall submit to the ISO, in such form, manner and detail as the ISO may reasonably prescribe, (i) any new or materially changed plan for additions to or changes to any generating and demand resources or transmission facilities rated 69 kV or above subject to control of such Market Participant or Transmission Owner, and (ii) any new or materially changed plan for any other action to be taken by the Market Participant or Transmission Owner, except for retirements of or reductions in the capacity of a generating resource or a demand resource, which may have a significant effect on the stability, reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant. No significant action (other than preliminary engineering action) leading toward implementation of any such new or changed plan shall be taken earlier than sixty days (or ninety days, if the ISO determines that it requires additional time to consider the plan and so notifies the Market Participant in writing within the sixty days) after the plan has been submitted to the ISO. Unless prior to

the expiration of the sixty or ninety days, whichever is applicable, the ISO notifies the Market Participant or Transmission Owner in writing that it has determined that implementation of the plan will have a significant adverse effect upon the reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant, the Market Participant or Transmission Owner shall be free to proceed. The ISO shall maintain on its website a list of such applications that are currently under review and the status of each such application. The ISO shall provide notice of any action taken with respect to any such applications, including an explanation of its reasons for such action, to each Market Participant or Transmission Owner as soon as reasonably practicable after such action is taken. The time limits provided by this section may be changed with respect to any such submission by agreement between the ISO and the Market Participant or Transmission Owner.

I.3.9.2 Additional Review of Additions of or Changes to Generating Resources:

Proposals for new generating resources or modifications to existing generating resources are also subject to the terms set out in Schedule 22, the Large Generator Interconnection Procedures and Agreement, and Schedule 23, the Small Generator Interconnection Procedures and Agreement, to Section II of the Tariff.

I.3.9.3 Reliability Review of Retirements of or Reductions in Capacity of an Existing Demand Capacity Resource or Existing Generating Capacity Resource:

Proposals for the reduction of capacity from an Existing Demand Capacity Resource or an Existing Generating Capacity Resource below its Qualified Capacity amount for the relevant Capacity Commitment Period, including unit retirement, are reviewed for reliability impact pursuant to the terms set out in Section III.13.2.5.2.5 of the Tariff. Once a demand resource or generating resource has a cleared de-list bid pursuant to Section III of the Tariff it may reduce its capacity consistent with the terms of its de-list bid for all or any part of the Capacity Commitment Period of the approved de-list without further reliability review. However, any proposed physical modification to a de-listed generating facility must comply with the requirements, including the reliability review process, set out in Schedules 22 or 23, as applicable.

I.3.10. Market Participant to Avoid Adverse Effect:

If the ISO notifies a Market Participant pursuant to Section I.3.9.1 that implementation of the Market Participant's or Transmission Owner's plan has been determined to have a significant adverse effect upon the reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of one or more Market Participants,

the Market Participant or Transmission Owner shall not proceed to implement such plan unless the Market Participant (or the Non-Market Participant on whose behalf the Market Participant has submitted its plan) or Transmission Owner takes such action or constructs at its expense such facilities as the ISO determines to be reasonably necessary to avoid such adverse effect.

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STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). 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, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as “Section III.1.4 Transactions,” and individually as a “Section III.1.4 Transaction.” Transactions that conform to the standards are referred to collectively as “Section III.1.4 Conforming Transactions,” and individually as a “Section III.1.4 Conforming Transaction.”

III.1.4.3 **Requirements for Section III.1.4 Conforming Transactions.**

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a “Related Transaction”), where the Related Transaction:

- (i) is not cleared or settled by the ISO as Counterparty;
- (ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

- (iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and
 - (iv) is not contingent on either party to carry out the Section III.1.4 Transaction.
- (b) In addition, to qualify as a Section III.1.4 Conforming Transaction:
- (i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;
 - (ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and
 - (iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.
- (c) As further requirements:
- (i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and
 - (ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

- (a) The following types of Claimed Capability Audits may be performed:
 - (i) An Establish Claimed Capability Audit establishes the Generator Asset's ability to respond to ISO dispatch instructions and to maintain performance at a specified output level for a specified duration.
 - (ii) A Seasonal Claimed Capability Audit determines a Generator Asset's capability to perform under specified summer and winter conditions for a specified duration.

- (iii) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.
- (iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR Audit value.
- (b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.
- (c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.
- (d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.
- (e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

- (a) An Establish Claimed Capability Audit may be performed only by a Generator Asset.
- (b) The time and date of an Establish Claimed Capability Audit shall be unannounced.
- (c) For a newly commercial Generator Asset:
 - (i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:
 1. Non-intermittent daily cycle hydro;
 2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
 3. Intermittent Generator Assets
 - (ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
 - (iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.
- (d) For Generator Assets with an Establish Claimed Capability Audit value:

- (i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.
 - (ii) An Establish Claimed Capability Audit shall be performed within five Business Days of the date of the request.
 - (iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
 - (iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
 - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (e) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.
 - (f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.
 - (g) To conduct an Establish Claimed Capability Audit, the ISO shall:
 - (i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.
 - (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.
 - (h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
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
Hydraulic Turbine – Other	
Hydro-Conventional Daily Pondage	2
Hydro-Conventional Run of River	
Hydro-Conventional Weekly	
Wind	2
Photovoltaic	
Fuel Cell	
Energy Storage (Excludes Pumped Storage)	2

- (i) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a unit type not listed in Section III.1.5.1.2(h).

III.1.5.1.3. Seasonal Claimed Capability Audits.

- (a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.
- (b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:
- (i) Non-intermittent daily hydro; and
 - (ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).
- (c) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset’s Seasonal Claimed Capability Audit obligation.
- (d) Except as provided in Section III.1.5.1.3(n) below, a summer Seasonal Claimed Capability Audit must be conducted:
- (i) At least once every Capability Demonstration Year;
 - (ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.
- (e) A winter Seasonal Claimed Capability Audit must be conducted:
- (i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:

- (1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.
 - (2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.
- (ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.
- (f) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:
- (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.
 - (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.
- (g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
- (h) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.
- (i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Unit Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2
Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2

Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible Hydraulic Turbine-Other	2
Hydro-Conventional Weekly	2
Fuel Cell	1
Energy Storage (Excludes Pumped Storage)	2

- (k) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:
- (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;
 - (ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and
 - (iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.
- (l) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:
- (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;
 - (ii) Retain the current Seasonal Claimed Capability Audit value for the season; and
 - (iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.
- (m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In

the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

- (n) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:
 - (i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(f).
 - (ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.
 - (iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.
 - (iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(d)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.
 - (v) This Section III.1.5.1.3(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.
- (o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a unit type not listed in Section III.1.5.1.3(j).

III.1.5.1.3.1 Seasonal DR Audits.

- (a) A Seasonal DR Audit may be performed only by a Demand Response Resource.
- (b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.
- (c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:
 - (i) At least once every Capability Demonstration Year;

- (ii) During the months of April through November;
- (d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:
 - (i) At least once every Capability Demonstration Year;
 - (ii) During the months of December through March.
- (e) A Seasonal DR Audit may be performed either:
 - (i) At the request of a Market Participant as described in subsection (f) below; or
 - (ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.
- (f) If a Market Participant requests a Seasonal DR Audit:
 - (i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.
 - (ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.
 - (iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
 - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:
 - (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.
 - (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.
 - (iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.
 - (iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.
- (h) An ISO-Initiated Claimed Capability Audit fulfills the Seasonal DR Audit obligation of a Demand Response Resource.

- (i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.
- (j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.
- (k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.
- (l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.
- (m) The Seasonal DR Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.
- (o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

- (a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.
- (b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:
 - (i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.

- (ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.
- (c) If for a Generator Asset a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.
- (d) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:
 - (i) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.
 - (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iii) For Generator Assets, begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.
 - (iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
- (f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit	
Asset or Resource 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
Hydraulic Turbine – Other	
Hydro-Conventional Daily Pondage	2
Hydro-Conventional Run of River	
Hydro-Conventional Weekly	
Wind	2
Photovoltaic	
Fuel Cell	
Energy Storage (Excludes Pumped Storage)	2
Demand Response Resource	1

- (g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource type not listed in Section III.1.5.1.4(f).

III.1.5.2 ISO-Initiated Parameter Auditing.

- (a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide real-time energy or reserves.
- (b) Generator audits shall be performed using the following methods for the relevant parameter:
- (i) **Economic Maximum Limit.** The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.
 - (ii) **Manual Response Rate.** The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.
 - (iii) **Start-Up Time.** The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.
 - (iv) **Notification Time.** The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.
 - (v) **CLAIM10.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5.
 - (vi) **CLAIM30.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5.

- (vii) **Automatic Response Rate.** The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.
- (viii) **Dual Fuel Capability.** A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).
- (c) Demand Response Resource audits shall be performed using the following methods:
 - (i) **Maximum Reduction.** The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.
 - (ii) **Demand Response Resource Ramp Rate.** The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.
 - (iii) **Demand Response Resource Start-Up Time.** The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.
 - (iv) **Demand Response Resource Notification Time.** The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.
 - (v) **CLAIM10.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5.
 - (vi) **CLAIM30.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5.
- (d) To conduct an audit based upon historical data, the ISO shall:
 - (i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or
 - (ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.
- (e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.

- (f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:
 - (i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.
 - (ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.
- (g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.
- (h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:
 - (i) The Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:
 1. Provide an explanation of the discrepancy;
 2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
 3. Indicate the timeline for completing the restoration; and
 4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.
 - (ii) The ISO shall:
 1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
 2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
 3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

- (a) Two types of Reactive Capability Audits may be performed:

- (i) A Lagging Reactive Capability Audit measures the Generator Asset's ability to provide reactive power to the transmission system at a specified real power output.
- (ii) A Leading Reactive Capability Audit measures the Generator Asset's ability to absorb reactive power from the transmission system at a specified real power output.
- (b) The ISO shall develop a list of Generator Assets that must conduct Reactive Capability Audits.
- (c) Unless otherwise directed by the ISO, Generator Assets that are required to perform Reactive Capability Audits must perform both a Lagging Reactive Capability Audit and a Leading Reactive Capability Audit.
- (d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.
- (e) The Reactive Capability Audit value of a 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.
- (f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.
- (g) Reactive Capability Audits must be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Generator Asset to conduct Reactive Capability Audits more often than every five years if:
 - (i) there is a change in the Generator Asset that may affect the reactive power capability of the Generator Asset;
 - (ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Generator Asset; or
 - (iii) historical data shows that the amount of reactive power that the Generator Asset can provide to or absorb from the transmission system is higher or lower than the latest audit data.
- (h) The Lead Market Participant may request a waiver of the requirement to conduct a Reactive Capability Audit. The ISO, at its sole discretion, will determine whether and for how long a waiver can be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 **ISO New England Manuals and ISO New England Administrative Procedures.**

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 **General.**

III.1.7.1 **Provision of Market Data to the Commission.**

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 **[Reserved.]**

III.1.7.3 **Agents.**

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 **[Reserved.]**

III.1.7.5 **[Reserved.]**

III.1.7.6 **Scheduling and Dispatching.**

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve

Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch.

(b) In the event that one or more Resources cannot be scheduled in the Day-Ahead Energy Market on the basis of a least-cost, security-constrained dispatch as a result of one or more Self-Schedule offers contributing to a transmission limit violation, the following scheduling protocols will apply:

(i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.

(ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.

(iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the Locational Marginal Price at each Location, determined by the ISO in accordance

with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.10 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 Seasonal DR Audit Value of an Active Demand Capacity Resource.

- (a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.
- (b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

III.1.7.13 [Reserved.]

III.1.7.14 **[Reserved.]**

III.1.7.15 **[Reserved.]**

III.1.7.16 **[Reserved.]**

III.1.7.17 **Operating Reserve.**

The ISO shall schedule the Operating Reserve and load-following requirements of the New England Control Area and the New England Markets in scheduling Resources pursuant to this Market Rule 1. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 **[Reserved.]**

III.1.7.19 **Ramping.**

A generating unit or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the unit's megawatt output or demand reduction level shall be able to change output or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that unit and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19A **Real-Time Reserve.**

(a) Real-Time TMSR, TMNSR, TMOR and Real-Time Replacement Reserve, if applicable, shall be supplied from Dispatchable Resources located within the metered boundaries of the New England Control Area subject to the condition set forth in Section III.1.7.19A(c) below. The ISO shall designate Operating Reserve in Real-Time only to Market Participant Resources that comply with the applicable standards and requirements for provision and dispatch of Operating Reserve capability as specified in Section III.10 and the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and locational Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) External Resources will be permitted to participate in the Real-Time reserve market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO units that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output or demand reduction levels of generating units or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating and demand reduction equipment is operated with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market, along with Dispatch Rate levels above which it does not desire to purchase.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning generating Resources, Demand Response Resources and Dispatchable Asset

Related Demand required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output or demand reduction capability for the pertinent Operating Day.

III.1.8 [Reserved.]

III.1.9 **Pre-scheduling.**

III.1.9.1 [Reserved.]

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 **Market Participant Responsibilities.**

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each generating unit as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 **Scheduling.**

III.1.10.1 **General.**

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy

Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of generating units or Demand Response Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers or Demand Reduction Offers.

III.1.10.1A 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) **Day-Ahead Locational Demand Bids** – Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resource increments, including hydropower units, Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant’s intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the energy Supply Offer limitation specified in this Section.

(b) [Reserved.]

(c) **Day-Ahead External Transactions** – All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction submitted under Section III.1.10.7 and that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer

Period. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

- (i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;
 - (ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;
 - (iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;
 - (iv) If the sum of all submitted fixed External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all fixed External Transaction sales at the applicable External Node shall be set equal to the Energy Offer Cap;
 - (v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.
- (d) **Day-Ahead Offers (Generator Assets and Dispatchable Asset Related Demand)** – Market Participants selling into the New England Markets, from either internal Resources (other than Demand Response Resources) or External Resources, shall submit Supply Offers or External Transactions for the supply of energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Operating Reserve or other services as applicable, for the following Operating Day. (Coordinated External Transactions shall be submitted to the ISO in accordance with Section III.1.10.7.A of this Market Rule 1.)

Such Supply Offers and Demand Bids:

- (i) Shall specify the Resource and energy for each hour of the Operating Day;

- (ii) Shall specify Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The price and quantity values in a Block may each vary on an hourly basis;
- (iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify, for Supply Offers, Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee values may vary on an hourly basis;
- (iv) For a dual fuel Resource, shall specify, for Supply Offers, the fuel type. The fuel type value may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual fuel Resources in Section III.A.3 of Appendix A;
- (v) Shall specify, for Supply Offers, a Minimum Run Time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;
- (vi) Supply Offers shall constitute an offer to submit the generating Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect maximum energy available for the Operating Day, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;
- (vii) Shall constitute, for Demand Bids, an offer to submit the Dispatchable Asset Related Demand Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes to the Maximum Consumption Limit and Minimum Consumption Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Minimum Consumption Limit may vary on an hourly basis to reflect the Self-Scheduled consumption level of the Resource;

(viii) Shall be final as to the price or prices at which the Market Participant proposes to supply or consume energy or other services to the New England Markets, such price or prices for Resources or portions of Resources scheduled in the Day-Ahead Energy Market being guaranteed by the Market Participant for the period extending through the end of the following Operating Day; and

(ix) Shall not specify an energy offer or bid price below the Energy Offer Floor or above the Energy Offer Cap.

(e) **Day-Ahead Offers (Demand Response Resources)** – Market Participants selling into the New England Markets from Demand Response Resources shall submit Demand Reduction Offers for the supply of energy, Operating Reserve or other services as applicable, for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Demand Reduction Offer.

Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The price and demand reduction quantity values may vary on an hourly basis.

(ii) Shall not specify a price that is above the Energy Offer Cap, below the Energy Offer Floor, or below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.

(f) **Demand Reduction Threshold Price** – The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

(a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.

(c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

(d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$D RTP = P_{th} X \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction Offer, or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Resource and an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) **Load Estimate** – The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) **Prorated Supply** – In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction Offer to be cleared on a

pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) **Prorated Demand** – In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) **Virtuals** – All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

(l) **DARD Pumps** – DARD Pumps will not be scheduled below their Minimum Consumption Limits.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers or Demand Reduction Offers or, for DARDs, submitted Demand Bids to purchase, to sell energy in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as generators, DARD Pumps or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy supply or consumption and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(b) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of

operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

(c) Market Participants offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) The Market Participant seller whose Resource is selected as a Pool-Scheduled Resource shall receive payments or credits for energy or related services, or for Start-Up Fees, No-Load Fees or Interruption Costs, from the ISO on behalf of the Market Participant buyers in accordance with Section III.3 of this Market Rule 1.

(e) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. Demand Response Resources shall not be Self-Scheduled.

(a) The minimum duration of a Self-Schedule for a Generator Asset or DARD Pump shall not result in the Generator Asset or DARD Pump operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer. A DARD Pump that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid.

(b) The offered prices of Resources or portions of Resources that are Self-Scheduled, or otherwise not following the dispatch orders of the ISO, shall not be considered by the ISO in determining Locational Marginal Prices.

(c) A Market Participant with a Resource that does not have a Capacity Supply Obligation shall comply with the requirements in Section III.13.6.2 when Self-Scheduling that Resource.

(d) A Market Participant Self-Scheduling a Resource in the Day-Ahead Energy Market that does not deliver the energy in the Real-Time Energy Market, shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.4 [Reserved.]

III.1.10.5 External Resources.

(a) Market Participants with External Resources that have dynamic scheduling and dispatch capability may submit Supply Offers to the New England Markets in accordance with the Day-Ahead and Real-Time scheduling processes specified above. Market Participants must submit Supply Offers for External Resources on a Resource specific basis. An External Resource with dynamic scheduling and dispatch capability selected as a Pool-Scheduled Resource shall be made available for scheduling and dispatch at the direction of the ISO and shall be compensated on the same basis as other Pool-Scheduled Resources.

(b) Supply Offers for External Resources with dynamic scheduling and dispatch capability shall specify the Resource being offered, along with the information specified in the Offer Data as applicable.

(c) For Resources external to the New England Control Area that are not capable of dynamic scheduling and dispatch, Market Participants shall submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

(d) A Market Participant whose External Resource is capable of dynamic scheduling and dispatch capability or whose External Transaction does not deliver the energy scheduled in the Day-Ahead Energy Market shall replace such energy not delivered as scheduled in the Day-Ahead Energy Market with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.6 Dispatchable Asset Related Demand.

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 Market Participant with a Dispatchable Asset Related Demand 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 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's ability to respond to Dispatch Instructions 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; 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.

In addition to the requirements of (a) through (h) above, a Market Participant with a DARD Pump may submit Maximum Daily Consumption Limits, Maximum Number of Daily Starts, Minimum Down Time, and a Minimum Run Time that meet the following criteria:

- Maximum Daily Consumption Limits and Maximum Number of Daily Starts are only for use in the Day-Ahead Energy Market and may be redeclared in the Re-Offer Period;
- Minimum Run Time and Minimum Down Time may not exceed one hour each and may be changed through redeclaration requests.

III.1.10.7 External Transactions.

The provisions of this Section III.1.10.7 do not apply to Coordinated External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the applicable procedures governing the Emergency, as set forth in ISO New England Manual 11, require a change in schedule.

(d) A Market Participant submitting a priced External Transaction supporting Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must comply with the requirements in Section III.13.6.1.2.1 with respect to

linking the transaction to the associated transmission reservation and NERC E-Tag. All other External Transactions submitted to the Real-Time Energy Market must contain the associated NERC E-Tag and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.7.A Coordinated External Transactions.

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An

Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated NERC E-Tag at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless applicable procedures governing the Emergency permit the transaction to be scheduled.

III.1.10.7.B Coordinated Transactions Scheduling Threshold Trigger to Tie Optimization

(a) Background and Overview

This Section III.1.10.B describes the process for filing amendments to the Transmission, Markets and Services Tariff under Section 205 of the Federal Power Act in the event that the production cost savings of the ISO's interchange on the New York – New England AC Interface, including the Northport/Norwalk Line, following the implementation of an inter-regional interchange scheduling process known as Coordinated Transaction Scheduling, are not satisfactory. The determination of whether savings are satisfactory will be based on actions, thresholds and triggers described in this Section III.1.10.7.B. If pursuant to the actions, thresholds and triggers described in this Section III.1.10.7.B, the production costs savings of Coordinated Transaction Scheduling are not satisfactory, and a superior alternative has not become known, the ISO will file tariff amendments with the Commission to

implement the inter-regional interchange scheduling process described to the ISO stakeholders in 2011 as Tie Optimization.

If, pursuant to the timetables presented, the ISO determines the thresholds described herein have not triggered, the process for filing amendments to the ISO tariff as described herein ceases, the provisions of this Section III.1.10.7.B become null and void and the ISO will continue to implement Coordinated Transaction Scheduling unless and until future Section 205 filings are pursued to amend Coordinated Transaction Scheduling.

(b) The Two-Year Analysis

Within 120 days of the close of the first and second years following the date that Coordinated Transaction Scheduling as an interface scheduling tool is activated in the New England and New York wholesale electricity markets, the External Market Monitor will develop, for presentation to and comment by, New England stakeholders, an analysis, of:

(i) the Tie Optimization interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the ISO and New York Independent System Operator received an infinite number of zero bids in the Coordinated Transaction Scheduling process, which utilizes the supply curves and forecasted prices for each market; and

(ii) an optimal interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the two ISOs had an infinite number of zero bids in the Coordinated Transaction Scheduling process, but utilizing actual real-time prices from each market rather than the forecasted prices that were used in the Coordinated Transaction Scheduling process.

The bid production cost savings associated with the Tie Optimization interchange as developed in (i) above for the second year following the date that Coordinated Transaction Scheduling is activated in the New England and New York wholesale electricity markets will reveal the “foregone” production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(b)(1) formula as the term “b.” The difference in bid production cost savings between (i) and (ii) above will reveal the “foregone” bid production cost savings of the Tie Optimization interchange as developed in (i) above rather than an optimal interchange as developed in (ii) above, represented in the Section III.1.10.7.B(b)(1) formula as the term “a.”

This analysis will be consistent with presentations made by the External Market Monitor to the New England stakeholders during 2011 on the issue of the benefits of Coordinated Transaction Scheduling.

- (1) Using the above calculations, the External Market Monitor will compute the following ratio:

b/a

If, the ratio b/a is greater than 60% and b is greater than \$3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(c) Improving Coordinated Transaction Scheduling

- (1) If the ratio, developed pursuant to Section III.1.10.7.B(b)(1), is greater than 60% and b is greater than \$3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

- (2) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

- (3) If the ISO declares that the threshold has triggered, the External Market Monitor will provide recommendations of adjustments to the design or operation of Coordinated Transaction Scheduling to improve the production cost savings available from its implementation.

- (4) The ISO, considering the input of the New England stakeholders and the recommendation of the External Market Monitor, will develop and implement adjustments to Coordinated Transaction Scheduling. To the extent tariff revisions are necessary to implement the adjustments to Coordinated Transaction Scheduling, the ISO will file such revisions with the Commission as a compliance filing in the Coordinated Transaction Scheduling docket. If no adjustments to Coordinated Transaction Scheduling have been identified, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing.

(d) The Second Analysis

(1) Within 120 days of the close of the twelve months following the date that the adjustments to Coordinated Transaction Scheduling, developed under Section III.1.10.7.B(c), are activated in the New England and New York wholesale electricity markets, the External Market Monitor will present a second analysis to New England stakeholders. The analysis will be consistent with the analysis described in Section III.1.10.7.B(b) but will develop bid production cost savings for the twelve month period during which the adjustments developed in Section III.1.10.7.B(c) are in place.

(2) The bid production cost savings associated with the Tie Optimization interchange as developed in Section III.1.10.7.B(d)(1) will reveal the “foregone” bid production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(d)(3) formula as the term “b.” The difference in bid production cost savings between the Tie Optimization interchange and the optimal interchange, as developed in Section III.1.10.7.B(d)(1), will reveal the “foregone” bid production cost savings of the Tie Optimization interchange rather than the optimal interchange, represented in the Section III.1.10.7.B(d)(3) formula as the term “a.”

(3) Using the above calculations, the External Market Monitor will compute the following ratio:

b/a

If the ratio b/a is greater than 60% and b is greater than \$3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(4) If the ratio b/a is greater than 60% and b is greater than \$3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(5) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(6) If the ISO declares the threshold has triggered, considering the input of the stakeholders and the recommendation of the External Market Monitor, the ISO will determine whether a superior alternative has been proposed. If the ISO and the New York Independent System Operator both determine a superior alternative has been proposed, the ISO will prepare tariff amendments to be filed

with the Commission to implement the superior alternative, and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments and will not pursue the balance of the actions required by this Section III.1.10.7.B.

(7) If the ISO determines a superior alternative has not been proposed, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing. Tie Optimization was described for stakeholders in the *Design Basis Document* for NE/NY Inter-Regional Interchange Scheduling presented at a NEPOOL Participants Committee meeting on June 10, 2011.

(e) The Compliance Filing

The ISO will develop tariff language to implement the inter-regional interchange scheduling practice known as Tie Optimization through a compliance filing with the Commission and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments.

III.1.10.8 ISO Responsibilities.

(a) The ISO shall use its best efforts to determine (i) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market. In making these determinations, the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve

and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Resources and to direct that schedules be changed to address an actual or potential Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to generation Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at

the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) During the Re-Offer Period, Market Participants may submit revisions to priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may at any time, consistent with the provisions in Manual 11, request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(c) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

- (i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual fuel Resources), the quantity and price pairs of its Blocks, and the Supply Offer for Regulation may be modified.
- (ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

(e) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or

worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit. A Market Participant may not request to Self-Schedule a Demand Response Resource.

(f) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(c), then:

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched as though it had offered for the hour in question at a Self-Scheduled MW.

(g) 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.

(h) DARD Pumps will not be scheduled in Real-Time below their Minimum Consumption Limits.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource 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, consumption or demand reduction of Resource increments as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (c) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Dispatchable Resources.

With the exception of Settlement Only Resources, External Transactions, nuclear-powered Resources and photovoltaic Resources, all Resources must be Dispatchable Resources and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-

Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources are subject to the following requirements:

- (a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.
- (b) The ISO shall implement the dispatch of energy from Dispatchable Resource increments and the designation of Real-Time Operating Reserve to Dispatchable 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. Each Market Participant shall ensure that the entity controlling a Dispatchable Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.
- (c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.
- (d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.
- (e) Intermittent Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind and hydro Intermittent Power Resources that are not Intermittent Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

(i) A wind or hydro Intermittent Power Resource not capable of receiving and responding to electronic Dispatch Instructions will be manually dispatched.

(ii) A Market Participant may elect, but is not required, to have a wind or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.

(iii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.

(f) The ISO may request that dual-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 Dispatchability Requirements for Intermittent Power Resources.

- (a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.
- (b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-

Time. Redclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

III.1.11.6 Non-Dispatchable Resources.

Non-Dispatchable Resources are subject to the following requirements:

(a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

III.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, DRR Aggregation Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of generation supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area,

transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices shall be determined every five minutes and such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and locational Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the power flow solution produced by the State Estimator for the pricing interval, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which

shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Adjustment for Rapid Response Pricing Assets.

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee, No-Load Fee, or Interruption Cost is specified in the submitted Offer Data, a value of zero shall be used; if no Minimum Run Time, minimum consumption time, or Minimum Reduction Time is specified in the submitted Offer Data, or if the submitted Minimum Run Time, minimum consumption time, or Minimum Reduction Time is less than 15 minutes, a duration of 15 minutes shall be used; and the energy offer after adjustment shall not exceed the Energy Offer Cap.

- (a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Dispatchable Asset Related Demand, its Minimum Consumption Limit shall be set to zero; if the Rapid Response Pricing Asset is a Fast Start Demand Response Resource, its Minimum Reduction shall be set to zero.
- (b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.
- (c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.

- (d) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.
- (e) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.
- (f) If the Rapid Response Pricing Asset is a Dispatchable Asset Related Demand that has not satisfied its minimum consumption time, its energy offer shall be decreased by: (i) the Start-Up Fee divided by the product of the Maximum Consumption Limit and the minimum consumption time; and (ii) the No-Load Fee divided by the Maximum Consumption Limit.
- (g) If the Rapid Response Pricing Asset is a Dispatchable Asset Related Demand that has satisfied its minimum consumption time its energy offer shall be decreased by the No-Load Fee divided by the Maximum Consumption Limit.

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, Demand Response Resources, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demand Resources with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply or consume 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.2.7A(c); and (5) the effect on transmission losses caused by the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed for every five-minute interval, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5 shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes.

III.2.6 Calculation of Nodal Day-Ahead Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions resulting from the load specifications submitted by Market Participants, Supply Offers, Demand Reduction Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying an optimization method to minimize energy cost, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy

offer or bid as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Node.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available generation at its Economic Maximum Limit and demand reduction at the Demand Response Resource's Maximum Reduction, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

- (i) All fixed External Transaction sales are considered to be dispatchable at the Energy Offer Cap;
- (ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer, Demand Reduction 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 DRR Aggregation Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone or DRR Aggregation Zone. The load

weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and DRR Aggregation 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 nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMNSR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve or local TMOR, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a Resource shall be determined for each Resource that the ISO re-dispatches in order to provide additional Operating Reserve or local TMOR and shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the generating Resource, Demand Response Resource or Dispatchable Asset Related Demand Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve or local TMOR from the Resource's expected output, consumption, or demand reduction level if it had been dispatched in economic merit order.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the

linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the linear programming algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

<u>Requirement</u>	<u>Requirement Sub-Category</u>	<u>RCPF</u>
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 for every five-minute interval, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour.

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 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.

If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for the Real-Time Energy Market is five minutes and the settlement interval for the Day-Ahead Energy Market is hourly. The Real-Time Energy Market settlement is determined using the Metered Quantity For Settlement calculated in accordance with Section III.3.2.1.1.

(a) **Day-Ahead Energy Market Obligations** – For each Market Participant for each settlement interval, 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 settlement interval 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 settlement interval 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 Demand Reduction Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Demand Reduction Obligation at each Location equal to the MWhs of its Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market at that Location, increased by average avoided peak distribution losses. Day-Ahead Demand Reduction Obligations shall have a positive value.

(iv) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval 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.

(v) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation plus the Day-Ahead Demand Reduction Obligation at that Location.

(b) **Real-Time Energy Market Obligations Excluding Demand Response Resource**

Contributions – For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for unmetered load and any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by generating Resources, External Resources, and External Transaction purchases at that Location.

(iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation** – Each Market Participant shall have for each settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(c) **Real-Time Energy Market Obligations For Demand Response Resources**

Real-Time Demand Reduction Obligation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation at each Location equal to the MWhs of demand reduction provided by Demand Response Resources at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction produced by a Demand Response Resource are equal to the sum of the demand reductions produced by its constituent Demand Response Assets calculated pursuant to Section III.8.4, where the demand reductions, other than MWhs associated with Net Supply, are increased by average avoided peak distribution losses.

(d) **Real-Time Energy Market Deviations Excluding Demand Response Resource**

Contributions – For each Market Participant for each settlement interval, the ISO will determine the difference between the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) and the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). For purposes of this

calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

- (i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

- (ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

- (iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

- (iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between (1) the Real-Time Locational Adjusted Net Interchange and (2) the Day-Ahead Locational Adjusted Net Interchange minus the Day-Ahead Demand Reduction Obligation for that Location.

- (e) **Real-Time Energy Market Deviations For Demand Response Resources**
Real-Time Demand Reduction Obligation Deviation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(c)) and the Day-Ahead Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(a)). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour.

(f) **Day-Ahead Energy Market Charge/Credit** – For each Market Participant for each settlement interval, 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.

(g) **Real-Time Energy Market Charge/Credit Excluding Demand Response Resources** – For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

(h) **Real-Time Energy Market Charge/Credit For Demand Response Resources** – For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market associated with Demand Response Resources. The charge or credit shall be equal to the sum of the Market Participant's Location-specific Real-Time Demand Reduction Obligation Deviations for that settlement interval multiplied by the Real-Time Locational Marginal Prices. Such charges and credits shall be allocated on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load

Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by DARD Pumps.

(i) **Day-Ahead and Real-Time Congestion Revenue** – For each settlement interval, 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 Deviation Congestion Charge/Credits.

(j) **Day-Ahead Loss Revenue** – For each settlement interval, 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.

(k) **Day-Ahead Loss Charges or Credits** – For each settlement interval 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(j)). 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.

(l) **Real-Time Loss Revenue** – For each settlement interval, 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(o) and Emergency transactions as described under Section III.4.3(a).

(m) **Real-Time Loss Revenue Charges or Credits** – 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(l)). 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.

(n) **Non-Market Participant Loss** – Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(o) **Inadvertent Energy Revenue** – For each External Node, for each settlement interval the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at the External Node by the associated Real-Time Locational Marginal Price. For each settlement interval, the total Inadvertent Energy Revenue for a settlement interval shall equal the sum of the Inadvertent Energy Revenue values for each External Node for that interval.

(p) **Inadvertent Energy Revenue Charges or Credits** – 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(o)). 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, Real-Time Generation Obligations, and Real-Time Demand Reduction Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

III.3.2.1.1 Metered Quantity For Settlement.

For purposes of determining the Metered Quantity For Settlement, the five-minute telemetry value for a five-minute interval is the integrated value of telemetered data sampled over the five-minute period. For settlement calculations that require hourly revenue quality meter value from Resources that submit five-minute revenue quality meter data, the hourly revenue quality meter value is the average of five-minute revenue quality meter values for the hour. The Metered Quantity For Settlement is calculated as follows:

(a) For external interfaces, the Metered Quantity For Settlement is the scheduled value adjusted for any curtailment, except that for Inadvertent Interchange, the Metered Quantity For Settlement is the difference between the actual and scheduled values, where the actual value is

- (i) calculated as the five-minute telemetry value plus the difference between the hourly revenue quality meter value and the hourly average telemetry value, or
 - (ii) the five-minute revenue quality meter value, if five-minute revenue quality meter data are available.
- (b) For Resources submitting five-minute revenue quality meter data (other than Demand Response Resources), the Metered Quantity For Settlement is the five-minute revenue quality meter value.
- (c) For Resources with telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is calculated as follows:
- (i) In the event that in an hour, the difference between the average of the five-minute telemetry values for the hour and the revenue quality meter value for the hour is greater than 20 percent of the hourly revenue quality meter value and greater than 10 MW then the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour.
 - (ii) Otherwise, the Metered Quantity For Settlement is the telemetry profile of the revenue quality meter value equal to the five-minute telemetry value multiplied by a scale factor, where the scale factor is the hourly revenue quality meter value divided by the hourly average telemetry value.
- (d) For a Demand Response Resource, the Metered Quantity For Settlement equals the sum of the demand reductions of each of its constituent Demand Response Assets produced in response to a non-zero Dispatch Instruction, with the demand reduction for each such asset calculated pursuant to Section III.8.4.
- (e) For Resources without telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour.

III.3.2.2 Metering and Communication.

- (a) **Revenue Quality Metering and Telemetry for Assets other than Demand Response Assets**
The megawatt-hour data of each Generator Asset, Tie-Line Asset, and Load Asset must be metered and automatically recorded at no greater than an hourly interval using metering located at the asset's point of interconnection, in accordance with the ISO operating procedures on metering and telemetering. This metered value is used for purposes of establishing the hourly revenue quality metering of the asset.

The instantaneous megawatt data of each Generator Asset (except Settlement Only Resources) and each Dispatchable Asset Related Demand must be automatically recorded and telemetered in accordance with the requirements in the ISO operating procedures on metering and telemetering.

(b) Meter Maintenance and Testing for all Assets

Each Market Participant must adequately maintain metering, recording and telemetering equipment and must periodically test all such equipment in accordance with the ISO operating procedures on metering and telemetering. Equipment failures must be addressed in a timely manner in accordance with the requirements in the ISO operating procedures on maintaining communications and metering equipment.

(c) Additional Metering and Telemetry Requirements for Demand Response Assets

- (i) Market Participants must report to the ISO in real time a set of telemetry data for each Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of Demand Response Assets as measured at their Retail Delivery Points, and shall be reported to the ISO every five minutes. For a Demand Response Resource to provide TMSR or TMNSR, 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.
- (ii) 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 electrically 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 meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.
- (iii) If the Market Participant or the ISO finds that the metering or telemetry devices do not meet the accuracy requirements specified in the ISO New England Manuals and Operating Procedures, the Market Participant shall promptly notify the ISO and indicate when it expects to resolve the accuracy problem(s), or shall request that the affected Demand Response Assets be retired. Once such an issue becomes known and until it is resolved, the demand reduction value and Operating Reserve capability of any affected Demand Response Asset shall be excluded from the Demand Response Resource with which it is associated.

- (iv) The ISO may 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.

(d) Overuse of Flat Profiling

In the event a Market Participant's telemetry is replaced with an hourly flat profile pursuant to Section III.3.2.1.1(b) more than 20% of the online hours in a month and Market Participant's Resource has been online for over 50 hours in the month, the ISO may consult with the Market Participant for an explanation of the regular use of flat profiling and may request that the Market Participant address any telemetry discrepancies so that flat profiling is not regularly triggered.

Within 10 business days of issuance of such a request, the Market Participant shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for completing such remediation. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan.

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) For each settlement interval during an hour in which there are Emergency Energy purchases, the ISO calculates an Emergency Energy purchase charge or credit equal to the Emergency Energy purchase price minus the External Node Real-Time LMP for the interval, multiplied by the Emergency Energy

quantity for the interval. The charge or credit for each interval in an hour is summed to an hourly value. The ISO allocates the hourly charges or credits 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. Generating Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs or credits attributable to the purchase of Emergency Energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) For each settlement interval during an hour in which there are Emergency Energy sales, the ISO calculates Emergency Energy sales revenue, exclusive of revenue from the Real-Time Energy Market, received from other Control Areas to provide the Emergency Energy sales. The revenues for each interval in an hour is summed to an hourly value. Hourly net revenues 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. Generating Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency Energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A

New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load or in such other manner as may be described in ISO New England Manual M-28 (Market Rule 1 Accounting). Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6, and 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 specified in the ISO New England Manuals 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. Errors in telemetry values used in calculating Metered Quantity For Settlement are not eligible for correction under this Section III.3.8.

(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.7 Financial Transmission Rights Auctions

III.7.1 Auctions of Financial Transmission Rights.

Periodic auctions (“FTR Auctions”) to allow Eligible FTR Bidders to acquire or FTR Holders to sell FTRs shall be conducted by the ISO in accordance with the provisions of this Section. Non-Market Participants that want to participate in the FTR Auction and have satisfied the applicable financial assurance criteria will be charged a one time FTR Registration Fee of \$5,000.

III.7.1.1 Auction Period and Scope of Auctions.

- (a) FTR Auctions shall be held on an annual and monthly basis.

- (b) The annual FTR Auction shall be conducted for FTRs effective for a single calendar year in two sequential rounds. Twenty-five percent of the available network capacity shall be available for the initial round of the annual FTR Auction. The FTRs that remain feasible with fifty percent of the network capacity available and after deducting the network capability associated with FTRs sold in the initial round shall be made available during the second round of the annual FTR Auction.

- (c) The ISO shall conduct monthly FTR Auctions, after the completion of the annual FTR Auction, every month. FTRs shall be made available for monthly auctions as follows:
 - (i) When FTRs for a month are auctioned, all FTRs that remain feasible will be made available, after accounting for all FTRs transacted in the annual FTR Auctions.

III.7.1.2 FTR Auctions Assumptions.

For annual FTR Auctions, the auction assumptions, including the modeling assumptions to be used for the FTR Auctions and dates and times for the opening and closing of bid submission windows will be announced by the ISO no later than 90 days prior to the first effective day of the FTRs to be auctioned. For monthly FTR Auctions, the auction assumptions, including the modeling assumptions to be used for the FTR Auctions and dates and times for the opening and closing of bid submission windows will be announced by the ISO no later than 40 days prior to the first effective day of the FTRs to be auctioned.

III.7.2 Financial Transmission Rights Characteristics.

III.7.2.1 Reconfiguration of Financial Transmission Rights.

Using an appropriate linear programming model, the ISO shall reconfigure the FTRs offered or otherwise available for sale in any auction to maximize the value to the bidders of the FTRs sold, provided that any FTRs acquired at auction shall be simultaneously feasible in combination with those FTRs outstanding at the time of the auction and not sold in the auction. The linear programming model shall, while respecting transmission constraints and the maximum megawatt quantities of the bids and offers, select the set of simultaneously feasible FTRs with the highest total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers.

III.7.2.2 Specified Locations.

Auction bids for FTRs may specify any combination of receipt and delivery locations represented in the State Estimator model for which the ISO calculates and posts Locational Marginal Prices. Auction bids may specify receipt and delivery points from locations outside of the New England Control Area to locations inside the New England Control Area, from locations within the New England Control Area to locations outside of the New England Control Area, or to and from locations within the New England Control Area. Congestion over interfaces associated with non-PTF external tie lines is not subject to LMP-based congestion management and, therefore, no FTRs across such interfaces will be included in the FTR Auctions.

III.7.2.3 Transmission Congestion Revenues.

FTRs shall entitle holders thereof to credits only for Transmission Congestion Revenue, and shall not confer a right to credits for payments arising from or relating to transmission congestion made to any entity other than the ISO.

III.7.2.4 [Reserved.]

III.7.3 Auction Procedures.

III.7.3.1 Role of the ISO.

FTRs auctions shall be conducted by the ISO in accordance with standards and procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures, such standards and procedures to be consistent with the requirements of this Market Rule.

III.7.3.2 [Reserved.]

III.7.3.3 [Reserved.]

III.7.3.4 On-Peak and Off-Peak Periods.

The ISO will conduct separate auctions simultaneously for on-peak and off-peak periods. On-peak FTRs shall cover the periods from 7:00 a.m. up to the hour ending at 11:00 p.m. on Mondays through Fridays, except holidays as defined in the ISO New England Manuals and ISO New England Administrative Procedures. Off-peak FTRs shall cover the periods from 11:00 p.m. up to the hour ending 7:00 a.m. on Mondays through Fridays and all hours on Saturdays, Sundays, and NERC holidays as defined in the ISO New England Manuals and ISO New England Administrative Procedures. Each bid shall specify whether it is for an on-peak or off-peak period.

III.7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase FTRs shall be submitted during the applicable period set forth in Section III.7.1.2, and shall be in the form specified by the ISO in accordance with the requirements set forth below.

(b) Offers to sell shall identify the specific FTRs, by megawatt quantity and receipt and delivery points, offered for sale. An offer to sell a specified megawatt quantity of FTRs shall constitute an offer to sell a quantity of FTRs equal to or less than the specified quantity. An offer to sell may not specify a minimum quantity being offered. Each offer may specify a reservation price, below which the offeror does not wish to sell the FTR. Offers shall be subject to such applicable standards for the financial assurance of the offeror or for the posting of security for performance as the ISO shall establish.

(c) Bids to purchase shall specify the megawatt quantity, price per megawatt, and receipt and delivery points of the FTR that the bidder wishes to purchase. A bid to purchase a specified megawatt quantity of FTRs shall constitute a bid to purchase a quantity of FTRs equal to or less than the specified quantity. A bid to purchase may not specify a minimum quantity that the bidder wishes to purchase. A bid may specify as receipt or delivery points any Location for which the ISO calculates and posts Locational Marginal Prices in accordance with Section III.2 of this Market Rule and may include FTRs for which the associated Transmission Congestion Credits may have negative values. Bids shall be subject to such applicable standards for the financial assurance of the bidder or for the posting of security for performance as the ISO shall establish.

(d) Bids and offers shall be specified to the nearest 0.1 megawatt and the quantity shall be greater than zero.

III.7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of each bidding period, the ISO will create a base FTR power flow model that includes all outstanding FTRs that have previously been awarded for the period for which the auction was conducted and that were not offered for sale in the auction. The base FTR model for the annual FTR Auction will reflect the network topology and transmission operating limits in effect at the time the annual FTR Auction is conducted, adjusted for estimated scheduled transmission outages. Monthly FTR Auctions shall utilize the then current network topology and transmission operating limits, as adjusted for currently estimated scheduled transmission outages and outages of individual generating units to the extent that such outages impact voltage or stability limits. The base FTR models also will include estimated uncompensated parallel flows into each interface point of the New England Control Area.

(b) In accordance with the requirements of this Section and subject to all applicable transmission constraints and reliability requirements, the ISO shall determine the simultaneous feasibility of all outstanding FTRs not offered for sale in the auction and of all FTRs that could be awarded in the auction for which bids were submitted. The winning bids shall be determined from an appropriate linear programming model that, while respecting transmission constraints and the maximum megawatt quantities of the bids and offers, selects the set of simultaneously feasible FTRs with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected FTRs and there are insufficient FTRs to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the FTRs that can be awarded.

(c) FTRs shall be sold at the market-clearing price for FTRs between specified pairs of receipt and delivery points, as determined by the bid value of the marginal FTR that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all FTR paths based on the bid value of the marginal FTRs, which are those FTRs with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each FTR's path relative to the marginal FTRs' paths flow sensitivities on the binding transmission constraints.

III.7.3.7 Announcement of Winners and Prices.

(a) After the close of the first round of the annual FTR Auction, in accordance with the schedule published in the auction assumptions and prior to the open of the bidding window for the final-round annual auctions, the ISO shall post the auction prices and FTRs cleared between eligible bidding

locations, as specified in Section III.7.2.2, excluding the identity of the winning bidder. The identities of winning bidders and the quantities of FTRs cleared by individual bidders in the first round of the annual auction will not be published until the close of the final round of the annual FTR Auction.

After the close of the final round of the annual FTR Auction, the ISO shall post, in accordance with the schedule set forth in the auction assumptions and prior to the open of the bidding window for monthly auctions, the winning bidders, the megawatt quantity, and the receipt and delivery points for each FTR awarded in the annual auction and the price at which each FTR was awarded.

(b) After the close of the monthly FTR Auction process, in accordance with the schedule set forth in the auction assumptions and prior to the effective date of the auctioned FTRs, the ISO shall post the winning bidders, the megawatt quantity, and the receipt and delivery points for each FTR awarded in the auction and the price at which each FTR was awarded. The FTR awards and prices shall be final as posted and not subject to correction or other adjustment, and shall be used for purposes of settlement, except as provided in subsections (d) and (e).

(c) Before posting the final FTR awards and prices, the ISO shall make a good faith effort when clearing the FTR Auction to discover and correct any errors that may occur due to database, software or similar errors of the ISO or its systems.

(d) If the ISO determines based on a reasonable belief that there may be one or more errors in the final FTR awards and prices or if no FTR awards or prices 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 applicable posting deadlines specified in subsections (a) or (b), as appropriate, a notice that the FTR awards and prices 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 FTR awards and prices and shall post a notice stating its findings.

(e) Within three business days after posting an initial notice pursuant to subsection (d); the ISO shall either: (1) publish final or corrected FTR awards and prices, or (2) in the event that the ISO is unable to calculate and post final or corrected FTR awards and prices 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 FTR awards and prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

(f) Results of the on-peak auction and off-peak auction will be posted separately. The ISO shall not disclose the price specified in any bid to purchase or the reservation price specified in any offer to sell.

III.7.3.8 Auction Settlements.

All buyers and sellers of FTRs between the same points of receipt and delivery shall pay or be paid the market-clearing price, as determined in the auction, for such FTRs.

III.7.3.9 Allocation of Auction Revenues.

All auction revenues, net of payments to entities selling FTRs into the auction, shall be allocated as specified under Appendix C of this Market Rule.

III.7.3.10 Simultaneous Feasibility.

The ISO shall make the simultaneous feasibility determinations specified herein using appropriate power flow models of contingency-constrained dispatch. Such determinations shall take into account outages, network model-related changes, and expected configuration of transmission facilities in accordance with Section III.7.3.6(a). The goal of the simultaneous feasibility determination shall be to ensure that there are sufficient Transmission Congestion Revenues to satisfy all FTR obligations for the auction period under expected conditions.

III.7.3.11 [Reserved.]

III.7.3.12 Financial Transmission Rights in the Form of Options.

When the ISO has the necessary software and hardware, the FTR Auctions shall allow for the acquisition of FTRs that do not create potential obligations to pay.

III.8 Additional Requirements for Demand Response Assets and Demand Response Resources

III.8.1 Registration and Aggregation

III.8.1.1 Demand Response Asset Registration and Aggregation

- (a) A Demand Response Asset must have a Maximum Interruptible Capacity of at least 10 kW.
- (b) A Demand Response Asset must have a single Retail Delivery Point and be registered at a single Node, unless it meets the conditions for aggregation in Section III.8.1(e).
- (c) No more than one Demand Response Asset may be registered at a Retail Delivery Point.
- (d) A Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.
- (e) A Demand Response Asset may be the aggregate demand reduction capability of multiple end-use customers with multiple Retail Delivery Points within a single DRR Aggregation Zone if (i) the demand reduction from each Retail Delivery Point is less than 10 kW and (ii) the demand at all Retail Delivery Points represents a homogeneous population as determined by the ISO. A Demand Response Asset that meets these conditions for aggregation must be registered at a DRR Aggregation Zone.
- (f) A Demand Response Asset with a Maximum Interruptible Capacity equal to or greater than 5 MW at a single Retail Delivery Point must be registered as a single Demand Response Resource at a single Node.
- (g) The metering and communication equipment associated with each Demand Response Asset must meet the requirements in Section III.3.2.2 and ISO New England Operating Procedure No. 18, Metering and Telemetry Criteria.
- (h) Upon request, the ISO will inform a load serving entity if (i) any of its end-use customers' facilities are registered as Demand Response Assets and (ii) the load reduction capability of any such Demand Response Assets.

III.8.1.2 Demand Response Resource Registration and Aggregation

- (a) A Demand Response Resource must be comprised of one or more Demand Response Assets within the same DRR Aggregation Zone.
- (b) A Demand Response Resource must be capable of at least 0.1 MW of demand reduction.
- (c) A Demand Response Resource cannot be comprised of: (i) 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 reduction capability to be bid into the ISO-administered markets or programs or (ii) 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 reduction capability to be bid into the ISO-administered markets or programs.

- (d) Each Demand Response Resource registered by a Market Participant within a single DRR Aggregation Zone must have a demand reduction capability of at least 1 MW before the Market Participant registers a new Demand Response Resource within the same DRR Aggregation Zone, unless either:
 - (i) all the Demand Response Resources registered by the Market Participant in the DRR Aggregation Zone are associated with an Active Demand Capacity Resource and the Market Participant wishes to register a Demand Response Resource that is not; or
 - (ii) none of the Demand Response Resources registered by the Market Participant in the DRR Aggregation Zone are associated with an Active Demand Capacity Resource and the Market Participant wishes to register a Demand Response Resource that is.
- (e) If the Seasonal DR Audit value of a Demand Response Resource falls below 1 MW causing a Market Participant to have more than one Demand Response Resource in a single DRR Aggregation Zone with a Seasonal DR Audit value less than 1 MW, then that Market Participant must reassign its Demand Response Assets if doing so decreases the number of that Market Participant's Demand Response Resources within that DRR Aggregation Zone, unless either:
 - (i) the Demand Response Resource with a Seasonal DR Audit value less than 1 MW is associated with an Active Demand Capacity Resource and the other of the Market Participant's Demand Response Resources are not; or
 - (ii) the Demand Response Resource with a Seasonal DR Audit value less than 1 MW is not associated with an Active Demand Capacity Resource and the other of the Market Participant's Demand Response Resources are.

III.8.2 Demand Response Baselines

- (a) A Demand Response Baseline is calculated for each Demand Response Asset for the following three day types:
 - (i) weekdays (excluding Demand Response Holidays);
 - (ii) Saturdays; and
 - (iii) Sundays and Demand Response Holidays.

- (b) A Market Participant shall not take any action to create or maintain a Demand Response Baseline that exceeds the typical electricity consumption levels of its end-use metered customers expected in the normal course of business.
- (c) A Market Participant may not submit Demand Reduction Offers for a Demand Response Resource for a given Operating Day unless a baseline for that day type for at least one Demand Response Asset assigned to the Demand Response Resource was established at least two calendar days prior to that Operating Day.
- (d) If a Demand Response Asset produces Net Supply in an interval, that Net Supply will be used in the Demand Response Baseline calculations for that interval.

III.8.2.1 Determining the Weekday Non-Holiday Demand Response Baseline

A Demand Response Asset's weekday (non-Demand Response Holiday) Demand Response Baseline in each five-minute interval is equal to the average of the asset's meter data for the same five-minute interval from 10 prior non-Demand Response Holiday weekdays, as follows:

- (a) For a Demand Response Asset without a weekday Demand Response Baseline, the initial weekday Demand Response Baseline will be created using meter data from the first 10 consecutive non-Demand Response Holiday weekdays with a complete set of five-minute interval meter data.
- (b) For a Demand Response Asset that has established a weekday Demand Response Baseline, the baseline will be updated using meter data from:
 - (i) the 10 most recent of the previous 30 non-Demand Response Holiday weekdays, excluding days during which: (1) the resource associated with the asset received a Dispatch Instruction for an amount greater than 0 MW or (2) the asset was on a forced or scheduled curtailment as described in Section III.8.3;
 - (ii) if there are fewer than 10 such days, then meter data from additional days will be used (until a total of 10 days have been identified) including, first, the most recent days during which the resource associated with the asset received a Dispatch Instruction for an amount greater than 0 MW and, second, the most recent days during which the asset was on a forced or scheduled curtailment as described in Section III.8.3.

III.8.2.2 Determining the Saturday Demand Response Baseline

A Demand Response Asset's Saturday Demand Response Baseline in each five-minute interval is equal to the average of the asset's meter data for the same five-minute interval from five prior Saturdays as follows:

- (a) For a Demand Response Asset without a Saturday Demand Response Baseline, the Saturday Demand Response Baseline will be created using meter data from the first five consecutive Saturdays with a complete set of five-minute interval meter data.
- (b) For a Demand Response Asset that has established a Saturday Demand Response Baseline, the baseline will be updated using meter data from:
 - (i) the five most recent Saturdays of the previous 42 calendar days, excluding Saturdays during which: (1) the resource associated with the asset received a Dispatch Instruction for an amount greater than 0 MW or (2) the asset was on a forced or scheduled curtailment as described in Section III.8.3.
 - (ii) if there are fewer than five such Saturdays, then, in addition to those days, meter data from the most recent Saturdays will be used, until five days are identified.

III.8.2.3 Determining the Sunday and Demand Response Holiday Demand Response Baseline

A Demand Response Asset's Sunday and Demand Response Holiday Demand Response Baseline in each five-minute interval is equal to the average of the asset's meter data for the same five-minute interval from five prior Sundays or Demand Response Holidays as follows:

- (a) For a Demand Response Asset without a Sunday and Demand Response Holiday Demand Response Baseline, the Sunday and Demand Response Holiday Demand Response Baseline will be created using meter data from the first five consecutive Sundays and Demand Response Holidays with a complete set of five-minute interval meter data.
- (b) For a Demand Response Asset that has established a Sunday and Demand Response Holiday Demand Response Baseline, the baseline will be updated using meter data from:
 - (i) the five most recent Sundays or Demand Response Holidays of the previous 42 calendar days, excluding Sundays or Demand Response Holidays during which: (1) the resource associated with the asset received a Dispatch Instruction for an amount greater than 0 MW or (2) the asset was on a forced or scheduled curtailment as described in Section III.8.3;
 - (ii) if there are fewer than five such Sundays or Demand Response Holidays, then, in addition to those days, meter data from the most recent Sunday or Demand Response Holiday will be used, until five days are identified.

III.8.2.4 Demand Response Baseline Adjustment

- (a) The ISO will calculate an adjustment to the Demand Response Baseline of a Demand Response Asset in each interval in which its associated Demand Response Resource receives a non-zero Dispatch Instruction. The adjustment can result in a higher or lower Demand Response Baseline during the dispatch.
- (b) The adjustment is equal to the average megawatt difference between the Demand Response Asset's metered demand (which may reflect Net Supply) and its Demand Response Baseline during the three most recently completed five-minute intervals prior to the issuance of the start-up instruction; provided that, if there was a non-zero Dispatch Instruction during any of those three five-minute intervals, the adjustment during the current dispatch will equal the adjustment during the prior dispatch.
- (c) For Demand Response Assets that cannot produce Net Supply, the adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load.
- (d) For Demand Response Assets that can produce Net Supply, the adjusted Demand Response Baseline shall not be less than (that is, shall not result in output at the Retail Delivery Point that exceeds) the maximum megawatt amount approved in the applicable Interconnection Agreement and shall not exceed the asset's Maximum Facility Load.

III.8.3 Demand Response Asset Forced and Scheduled Curtailments

In addition to complying with the outage requirements described in ISO New England Operating Procedure No. 5, a Market Participant with a Demand Response Asset must abide by the following curtailment procedures.

- (a) Forced Curtailment – A Market Participant with a Demand Response Asset may notify the ISO of a forced curtailment, that is, a reduction in demand resulting from actions outside the control of the Demand Response Asset or the Market Participant subject to the forced curtailment.
- (b) Scheduled Curtailment – At least seven calendar days prior to the start of the curtailment, a Market Participant with a Demand Response Asset may notify the ISO of a scheduled curtailment, that is, a reduction in demand resulting from a scheduled plant shutdown or scheduled maintenance of energy consuming equipment. A scheduled curtailment may be no shorter than a single calendar day and the total duration of scheduled curtailments per Capacity Commitment Period may not exceed 14 calendar days.
- (c) Offers and Settlement – Except for the first day of a forced curtailment, (i) Demand Reduction Offer parameters may not include any contributions from a Demand Response Asset on a forced

or scheduled curtailment and (ii) a Demand Response Asset on a forced or scheduled curtailment shall not be eligible for payment in the Real-Time Energy Market.

III.8.4 Demand Response Asset Energy Market Performance Calculations

- (a) The ISO will calculate the demand reduction contribution of a Demand Response Asset in each interval in which its associated Demand Response Resource has received a non-zero Dispatch Instruction following the conclusion of the Demand Response Resource Notification Time. The demand reduction contribution by a Demand Response Asset to its Demand Response Resource shall equal the difference between the adjusted Demand Response Baseline of the Demand Response Asset and the metered demand of the Demand Response Asset, except as follows:
- (i) On the first day of a forced curtailment, a Demand Response Asset's demand reduction shall equal the difference between the unadjusted Demand Response Baseline of the Demand Response Asset and the metered demand of the Demand Response Asset; and
 - (ii) A Demand Response Asset shall be assessed a zero demand reduction on any day of a forced curtailment other than the first day; on any day of a scheduled curtailment; in any interval in which there is insufficient data to calculate the Demand Response Baseline; and in any interval in which the Market Participant fails to comply with the Demand Response Asset metering and communication requirements in Section III.3.2.2 or ISO New England Operating Procedure No. 18, Metering and Telemetry Criteria.
- (b) Notwithstanding the foregoing, an Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be calculated pursuant to Section III.13.7.2.2.

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 follow Dispatch Instructions during the Operating Day. The Resource must meet the technical requirements associated with the provision of Operating 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 Resource 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 Market Participant weekly and shall become effective at 0001 of the Monday following the distribution.
- 5. The values described in Sections III.9.5.3.1(1)(a) and (b) shall not include any dispatch where:
 - a) The Resource is dispatched at the request of the Market Participant or Designated Entity and the dispatch was not related to an Establish Claimed Capability Audit request made pursuant to Section III.1.5.1.2, a Seasonal DR Audit request made pursuant to Section III.1.5.1.3.1, or a CLAIM10 or CLAIM30 audit request made pursuant to Section III.9.5.3.2;
 - b) The prices associated with the Blocks to Economic Min for the Real-Time dispatch of the Resource are less than or equal to zero;

- c) For generating Resources, the ratio of (i) the sum of the applicable Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min used in the Real-Time dispatch of the Resource in the Operating Day to (ii) the maximum total hourly Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min submitted for the Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold value determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to (i) differences in cost between Gas Days, or (ii) a reduction in the cost of gas within the Operating Day reflected in the offers submitted for the Resource during the remainder of the Operating Day, then the Market Participant may request that the ISO evaluate whether the dispatch may be included; or
 - d) For Demand Response Resources, the ratio of (i) the sum of the applicable Interruption Cost and the demand reduction cost to Minimum Reduction used in the Real-Time dispatch of the Demand Response Resource in the Operating Day to (ii) the maximum total hourly Interruption Cost and demand reduction cost to Minimum Reduction submitted for the Demand Response Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to differences in cost between Gas Days, then the Market Participant may request that the ISO evaluate whether the dispatch may be included.
6. A Demand Response Resource's CLAIM10 and CLAIM30 values on June 1, 2018 and October 1, 2018 shall be as follows:
- a) On June 1, 2018 and October 1, 2018, the CLAIM10 value of a Demand Response Resource shall equal zero.
 - b) On June 1, 2018, the CLAIM30 value of a Demand Response Resource with one or more Demand Response Assets that were associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource" (as those terms were defined prior to June 1, 2018) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Summer Capability Period beginning June 1, 2017. Such a CLAIM30 value shall remain valid until the earlier of: (i) July 2, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 value pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before June 27, 2018, its CLAIM30 value shall be set to zero on July 2, 2018.

- c) On October 1, 2018, the CLAIM30 value of a Demand Response Resource with one or more Demand Response Assets that were associated with a “Real-Time Demand Response Resource” or a “Real-Time Emergency Generation Resource” (as those terms were defined prior to June 1, 2018) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Winter Capability Period beginning October 1, 2017. Such a CLAIM30 value shall remain valid until the earlier of: (i) October 29, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 value pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before October 24, 2018, its CLAIM30 value shall be set to zero on October 29, 2018.

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 not request more than one audit per week for the same Resource, provided that, if the Resource fails to start, trips offline, or becomes unavailable to provide a demand reduction during the audit, then the Market Participant may request another audit in the same week. The ISO, at its sole discretion, may allow a Market Participant to request more than one audit per week for the same Resource if the Resource historically has multiple startup dispatches included in its CLAIM10 or CLAIM30 calculations per week. 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:

$$\text{performance factor} = \frac{\sum_{n=1}^{10} (\text{resource output or demand reduction at 10 or 30 minutes}_n \text{ (MW)} * n)}{\sum_{n=1}^{10} n}$$

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 pursuant to Section III.8.3, 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 that are Generator Assets or Dispatchable Asset Related Demand 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, 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.

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 calculated as follows:

- (a) For each of the five most recently completed Summer Capability Periods or Winter Capability Periods (as applicable to the Forward Reserve Procurement Period), for each on-peak hour, the ISO shall calculate an implied heat rate, expressed in Btu/kWh, by dividing the hour's Hub Price by the lower of the applicable natural gas or heating oil price index.
- (b) All resulting hourly implied heat rates above 45,000 Btu/kWh shall be excluded, and the remaining values shall be listed in order from high to low.
- (c) The Forward Reserve Heat Rate for the Forward Reserve Procurement Period shall be the lesser of: (i) the heat rate that occurs at the 97.5th percentile of the list described in subsection (b) above; or (ii) 21,999 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.

- (a) **Generating Resources and Dispatchable Asset Related Demand** – 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 a generating Resource's 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:

$$\frac{StartUp}{EcoMax \times 1 \text{ hour}} + \frac{NoLoad}{EcoMax} + Energy \ Offer_i \geq ForwardReserveThresholdPrice$$

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 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.

(b) Demand Response Resources – 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:

$$\frac{\text{Interruption Cost}}{\text{MaxRed}} + \text{Energy Offer } i \geq \text{Forward Reserve Threshold Price}$$

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 increased by average avoided peak distribution losses, limited as described below.

- (i) The ISO will assume that Demand Response Resources first reduce their net load from the electricity system before providing additional Net Supply.
- (ii) The portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be the lesser of: (1) Forward Reserve Delivered Megawatts and (2) the amount of load that the Demand Response Resource can reduce from the electric system based on the net load of its constituent Demand Response Assets.
- (iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with Net Supply will be capped at the remaining Net Supply capability of the Demand Response Resource.

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 increased by average avoided peak distribution losses. The portion of the Target Activation Megawatts not associated with Net Supply shall be calculated as the greater of: (i) the Target Activation Megawatts minus the amount of Net Supply that the Demand Response Resource produced during activation or (ii) zero.

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)

$FRACP_{Zone}$ is defined as 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 to:

applicable monthly $FRACP_{Zone}$ for TMNSR 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:

applicable monthly FRACP_{Zone} for TMOR 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 TMNSR proxy system clearing price, plus the TMOR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the TMOR proxy system clearing price 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.

For purposes of this Section III.10, unless otherwise expressly stated, the settlement interval is five minutes. If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.10.1 Provision of Operating Reserve in Real-Time

For each Market Participant for each settlement interval, 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

(a) Each Market Participant shall have for each settlement interval 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 Metered Quantity For Settlement and the estimated Resource output utilized to determine the amount of Real-Time Reserve Designation.

(b) Each Market Participant shall have for each settlement interval 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 Metered Quantity For Settlement 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. Demand Response Resource credits will be limited as described in Section III.9.6.5(h).

(a) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMSR for an hour shall be equal to the sum of the Real-Time Reserve Credit for TMSR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMSR for an interval is calculated by multiplying the Market Participant's Resource specific Real-Time Reserve Designation for TMSR (where any portion of Real-Time Reserve Designation MW provided by a Demand Response Resource, other than MWs associated with Net Supply, is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMSR for the interval. The Real-Time Reserve Credit for TMSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific hourly Real-Time Reserve Credits for TMSR in that Load Zone.

(b) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMNSR shall be equal to the sum of the Real-Time Reserve Credit for TMNSR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMNSR for an interval is calculated by multiplying the Market Participant's Resource specific Real-Time Reserve Designation for TMNSR (where any portion of Real-Time Reserve Designation MW provided by a Demand Response Resource, other than MWs associated with Net Supply, is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMNSR for the interval. The Real-Time Reserve Credit for TMNSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific hourly Real-Time Reserve Credits for TMNSR in that Load Zone.

(c) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMOR shall be equal to the sum of the Real-Time Reserve Credit for TMOR (where any portion of Real-Time Reserve Designation MW provided by a Demand Response Resource, other than MWs associated with Net Supply, is increased by average avoided peak distribution losses) for the settlement intervals in that hour. The Real-Time Reserve Credit for TMOR for an interval is calculated by multiplying the Market Participant's Resource specific Real-Time Reserve Designation for TMOR for the interval by the Real-Time Reserve Clearing Price for TMOR for the interval. 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:

$$\text{Real-Time Reserve Charge}_{k,i} = [\text{Reserve Charge Allocation MW}_{k,i}] \times [\text{RT_CHRG_RT}_i]$$

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.

$\text{RT_CHRG_RT}_i = [\text{IRT_SUP_PMNT}]/\text{RT_P_WTD_LD_OB}] \times$
 $[\text{RT_P_RATIO}]$ for TMSR, TMNSR, or TMOR, as applicable.

$\text{RT_P_WTD_LD_OB} = \sum[\text{Reserve Charge Allocation MW}_{s,i}] \times$
 $[\text{P_RATIO}_i]$ for TMSR, TMNSR or TMOR, as applicable;

$[\text{RT_SUP_PMNT}] =$ 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_RATIO_i 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 settlement interval such that a Market Participant will not receive compensation for Real-Time Operating Reserve MWs provided to satisfy a Forward Reserve Obligation.

For purposes of the calculations in this Section III.10.4: (1) when a Market Participant assigns a Forward Reserve Resource in one Reserve Zone to meet a Forward Reserve Obligation in another Reserve Zone, any Forward Reserve Obligation Charge megawatts associated with that Resource are allocated to the Reserve Zone in which the Market Participant holds the Forward Reserve Obligation; and (2) if a Market Participant satisfies a Forward Reserve Obligation for TMOR with Forward Reserve Delivered MW of TMNSR, the Forward Reserve Obligation Charge megawatts are allocated to the Market Participant's Forward Reserve Obligation for TMOR.

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 portion of Real-Time Reserve Designation MW provided by a Demand Response Resource, other than MWs associated with Net Supply, 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.

III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

Prior to each Forward Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction in accordance with this Section III.12.1.

The ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation (“LOLE”) of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period. The Installed Capacity Requirement shall be determined assuming all resources pursuant to Sections III.12.7 and III.12.9 will be deliverable to meet the forecasted demand determined pursuant to Section III.12.8.

If the Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Installed Capacity Requirement. The modeling assumptions used in determining the Installed Capacity Requirement are specified in Sections III.12.7, III.12.8 and III.12.9. For the purpose of this Section III.12, a “resource” shall include generating resources, demand resources, and import capacity resources eligible to receive capacity payments in the Forward Capacity Market.

III.12.1.1. System-Wide Marginal Reliability Impact Values.

Prior to each Forward Capacity Auction, the ISO shall determine the system-wide Marginal Reliability Impact of incremental capacity at various capacity levels for the New England Control Area. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used in determining the Installed Capacity Requirement.

III.12.2. Local Sourcing Requirements and Maximum Capacity Limits.

Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section

III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction. The Local Sourcing Requirement shall represent the minimum amount of capacity that must be procured within an import-constrained Capacity Zone. The Maximum Capacity Limit shall represent the maximum amount of capacity that can be procured in an export-constrained Capacity Zone to meet the Installed Capacity Requirement.

The ISO shall use consistent assumptions and standards to establish a resource's electrical location for purposes of qualifying a resource for the Forward Capacity Market and for purposes of calculating Local Sourcing Requirements and Maximum Capacity Limits. The methodology used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.2.1 and III.12.2.2, respectively. The modeling assumptions used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.5, III.12.6, III.12.7, III.12.8 and III.12.9.

III.12.2.1. Calculation of Local Sourcing Requirements for Import-Constrained Capacity Zones.

For each import-constrained Capacity Zone, the Local Sourcing Requirement shall be the amount needed to satisfy the higher of: (i) the Local Resource Adequacy Requirement as determined pursuant to Section III.12.2.1.1; or (ii) the Transmission Security Analysis Requirement as determined pursuant to Section III.12.2.1.2.

III.12.2.1.1. Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

- (a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the import-constrained side of the interface, if any; and (ii) the rest of the New England Control Area which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits on the unconstrained side of the interface, if any.

- (b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Local Resource Adequacy Requirement for the import-constrained Capacity Zone Z shall be determined in accordance with the following formula:

$$LRA_Z = Resources_Z + Proxy Units_Z - (Proxy Units Adjustment_Z(1-FOR_Z)) - (Firm Load Adjustment_Z(1-FOR_Z))$$

In which:

LRA_Z = MW of Local Resource Adequacy Requirement for Capacity Zone Z;

$Resources_Z$ = MW of resources electrically located within Capacity Zone Z, including import Capacity Resources on the import-constrained side of the interface, if any;

$Proxy Units_Z$ = MW of proxy unit additions in Load Zone Z;

$Firm Load Adjustment_Z$ = MW of firm load added (or subtracted) within Capacity Zone Z to make the LOLE of the New England Control Area equal to 0.105 days per year; and

FOR_Z = Capacity weighted average of the forced outage rate modeled for all resources within Capacity Zone Z, including and proxy unit additions to Capacity Zone Z.

$Proxy Units$

Adjustment = MW of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1 days/year.

To determine the Local Resource Adequacy Requirement, the firm load is adjusted within Capacity Zone Z until the LOLE of the New England Control Area reaches 0.105 days per year. The LOLE of 0.105 days per year includes an allowance for transmission related LOLE of 0.005 days per year associated with each interface. As firm load is added to (or subtracted from) Capacity Zone Z, an equal amount of firm load is removed from (or added to) the rest of New England Control Area.

III.12.2.1.2. Transmission Security Analysis Requirement.

A Transmission Security Analysis shall be used to determine the requirement of the zone being studied, and shall include the following features:

- (a) The ISO shall perform a series of transmission load flow studies and/or a deterministic operable capacity analysis targeted at determining the performance of the system under stressed conditions, and at developing a resource requirement sufficient to allow the system to operate through those stressed conditions.
- (b) The Transmission Security Analysis Requirement shall be set at a level sufficient to cover most reasonably anticipated events, but will not guarantee that every combination of obligated resources within the zone will meet system needs.
- (c) In performing the Transmission Security Analysis, the ISO may establish static transmission interface transfer limits, as identified pursuant to Section III.12.5, as a reasonable representation of the transmission system's capability to serve load with available existing resources.
- (d) The Transmission Security Analysis may model the entire New England system and individual zones, for both the first contingency (N-1) and second contingency (N-1-1) conditions. First contingency conditions (N-1) shall include the loss of the most critical generator or most critical transmission element with respect to the zone. Second contingency conditions (N-1-1) shall include both: (i) the loss of the most critical generator with respect to the zone followed by the loss of the most critical transmission

element (“Line-Gen”); and (ii) the loss of the most critical transmission element followed by the loss of the next most critical transmission element (“Line-Line”) with respect to the zone.

III.12.2.1.3. Marginal Reliability Impact Values for Import-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each import-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) shall be reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero.

III.12.2.2. Calculation of Maximum Capacity Limit for Export-Constrained Capacity Zones.

For each export-constrained Capacity Zone, the Maximum Capacity Limit shall be calculated using the following method:

- (a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the export-constrained side of the interface, if any; and (ii) the rest of the New England Control Area, which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits to the rest of the New England Control Area, if any.
- (b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.
- (c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Maximum Capacity Limit for the export-constrained Capacity Zone Y shall be determined in accordance with the following formula:

$$\text{Maximum Capacity Limit}_Y = \text{ICR} - \text{LRA}_{\text{RestofNewEngland}}$$

In which:

Maximum Capacity Limit_Y = Maximum MW amount of resources, including Import Capacity Resources on the export-constrained side of the interface, if any, that can be procured in the export-constrained Capacity Zone Y to meet the Installed Capacity Requirement;

ICR = MW of Installed Capacity Requirement for the New England Control Area, determined in accordance with Section III.12.1; and

LRA_{RestofNewEngland} = MW of Local Sourcing Requirement for the rest of the New England Control Area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Section III.12.2.1.

III.12.2.2.1. Marginal Reliability Impact Values for Export-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each export-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit.

III.12.3 Consultation and Filing of Capacity Requirements.

At least two months prior to filing the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves with the Governance Participants, the state utility regulatory

agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act 90 days prior to the Forward Capacity Auction for the Capacity Commitment Period. The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given FCA, any new Capacity Zone must have received approval from the Commission prior to the Existing Capacity Qualification Deadline of the applicable FCA.

III.12.4. Capacity Zones.

For each Forward Capacity Auction, the ISO shall, using the results of the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K, determine the Capacity Zones to model as described below, and will include such designations in its filing with the Commission pursuant to Section III.13.8.1(c):

- (a) The ISO shall model in the Forward Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit is less than the sum of the existing qualified capacity and proposed new capacity that could qualify to be procured in the export constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface.

- (b) The ISO shall model in the Forward Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the second contingency transmission capability results in a line-line Transmission Security Analysis Requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, that is greater than the Existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model out-of-service all Retirement De-List Bids and Permanent De-List Bids (including any received for the current FCA at the time of this calculation) as well as rejected for

reliability Static De-List Bids from the most recent previous Forward Capacity Auction and rejected for reliability Dynamic De-List Bids from the most recent previous Forward Capacity Auction.

(c) Adjacent Load Zones that are neither export-constrained nor import-constrained shall be modeled together as the Rest of Pool Capacity Zone in the Forward Capacity Auction.

III.12.4A. 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 of Active Demand Capacity 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.12.5. Transmission Interface Limits.

Transmission interface limits, used in the determination of Local Sourcing Requirements, shall be determined pursuant to ISO Tariff Section II, Attachment K using network models that include all resources, existing transmission lines and proposed transmission lines that the ISO determines, in accordance with Section III.12.6, will be in service no later than the first day of the relevant Capacity Commitment Period. The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

III.12.6. Modeling Assumptions for Determining the Network Model.

The ISO shall determine, in accordance with this Section III.12.6, the generating units and transmission infrastructure to include in the network model that: (i) are expected to be in service no later than the first day of the relevant Capacity Commitment Period; and (ii) may have a material impact on the network model, a potential interface constraint, or on one or more Local Sourcing Requirements. The network model shall be used, among other purposes, (i) for the Forward Capacity Market qualification process and (ii) to calculate transmission interface limits in order to forecast the Local Sourcing Requirements. The network model shall include:

(a) For the relevant Capacity Commitment Period, the network model shall include:

(i) all existing resources, along with any associated interconnection facilities and/or Elective Transmission Upgrades that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Section III.13.2.5.2.5.3;

(ii) all new resources with Qualified Capacity for the relevant Capacity Commitment Period, along with any associated interconnection facilities and/or Elective Transmission Upgrades; and

iii. in the case of an initial interconnection analysis that is conducted consistent with the Network Capability Interconnection Standard, any generating unit or External Elective Transmission Upgrade that has a valid Interconnection Request and is reasonably expected to declare commercial operation no later than the first day of the relevant Capacity Commitment Period.

(b) Prior to each Forward Capacity Auction and each annual reconfiguration auction, the ISO shall determine and publish a list of the transmission projects and elements of transmission projects that will be included in the network model. During the process of making the transmission infrastructure determinations, as described in Section III.12.6.1, the ISO shall consult with the Governance Participants, the Transmission Owners, any transmission project proponents, the state utility regulatory agencies in New England and, as appropriate, other state agencies.

III.12.6.1. Process for Establishing the Network Model.

(a) The ISO shall establish an initial network model prior to the Forward Capacity Auction that only includes transmission infrastructure, including Internal Elective Transmission Upgrades, that is already in service at the time that the initial network model is developed.

(b) After establishing the initial network model, the ISO shall compile a preliminary list of the transmission projects or elements of transmission projects in the RSP Project List, individually or in combination with each other, as appropriate, to identify transmission projects that may achieve an in-service date no later than the first day of the relevant Capacity Commitment Period and that will have a material impact on the network model, on a potential interface constraint or one or more Local Sourcing Requirements.

(c) For the transmission projects or elements of transmission projects in the RSP Project List that are included in the preliminary list developed pursuant to subsection (b), the ISO shall determine whether the transmission projects or elements of transmission projects meet all of the initial threshold milestones specified in Section III.12.6.2 and will be considered for further evaluation pursuant to subsection (d).

(d) For those transmission projects or elements of transmission projects that meet the initial threshold milestones in subsection (c), the ISO shall use the evaluation criteria specified in Section III.12.6.3, and any other relevant information, to determine whether to include a transmission project or element of a transmission project in the final network model.

(e) If after completing its evaluation pursuant to Sections III.12.6.1 through III.12.6.3 and conferring with the transmission project proponents, the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO determines that the transmission project or a portion of the transmission project is reasonably expected to be in service no later than the first day for the relevant Capacity Commitment Period, then such transmission project or portion of transmission project shall be considered in service in the finalized network model to calculate the transmission interface limits pursuant to Section III.12.5.

III.12.6.2. Initial Threshold to be Considered In-Service.

The ISO shall determine whether transmission projects or elements of transmission projects meet all of the following initial threshold milestones:

(a) A critical path schedule for the transmission project has been furnished to ISO showing that the transmission project or the element of the transmission project will be in-service no later than the first day of the relevant Capacity Commitment Period. The critical path schedule must be sufficiently detailed to allow the ISO to evaluate the feasibility of the schedule.

(b) At the time of the milestone review, siting and permitting processes, if required, are on schedule as shown on the critical path schedule.

(c) At the time of the milestone review, engineering is on schedule as shown on the critical path schedule.

(d) At the time of the milestone review, land acquisition, if required, is on schedule as shown on the critical path schedule.

(e) Corporate intent to build the transmission project has been furnished to the ISO. An officer of the host Transmission Owner or Elective Transmission Upgrade Interconnection Customer has submitted to the ISO a statement verifying that the officer has reviewed the proposal and critical path schedule submitted to the ISO, and the Transmission Owner or Elective Transmission Upgrade Interconnection Customer concurs that the schedule is achievable, and it is the intent of the Transmission Owner or Elective Transmission Upgrade Interconnection Customer to build the proposed transmission project in accordance with that schedule. The Transmission Owner or Elective Transmission Upgrade Interconnection Customer may develop alternatives or modifications to the transmission project during the course of design of the transmission project that accomplish at least the same transfer capability. Such alternatives or modifications are acceptable, so long as the ISO determines that the alternative or modification is reasonably expected to achieve an in-service date no later than the first day of the relevant Capacity Commitment Period. The provision of an officer's statement shall be with the understanding that the statement shall not create any liability on the officer and that any liability with respect to the Transmission Owner's obligations shall be as set forth in the Transmission Operating Agreement and shall not be affected by such officer's statement.

III.12.6.3. Evaluation Criteria.

For a transmission project or element of a transmission project that meets the initial threshold milestones specified in Section III.12.6.2, the ISO shall consider the following factors and any other relevant information to determine whether to include the transmission project or element of the transmission project in the network model for the relevant Capacity Commitment Period.

(a) Sufficient engineering to initiate construction is on schedule as shown on the critical path schedule.

(b) Approval under Section I.3.9 of the Transmission, Markets and Services Tariff, if required, has been obtained or is on schedule to be obtained as shown on the critical path schedule.

(c) Significant permits, including local permits, if required to initiate construction have been obtained or are on schedule consistent with the critical path schedule.

- (d) Easements, if required, have been obtained or are on schedule consistent with the critical path schedule. Needed land purchases, if required, have been made or are on schedule consistent with the critical path schedule.
- (e) Any contracts required to procure or construct a transmission project are in place consistent with the critical path schedule. The ISO's analysis may also take into account whether such contracts contain incentive and/or penalty clauses to encourage third parties to advance the delivery of material services to conform with the critical path schedule.
- (f) Physical site work is on schedule consistent with the critical path schedule.
- (g) The transmission project is in a designated National Interest Electric Transmission Corridor in accordance with Section 216 of the Federal Power Act, 16 U.S.C. §§ 824p.

III.12.7. Resource Modeling Assumptions.

III.12.7.1. Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as additional capacity to determine the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all other resources in the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

When modeling transmission constraints for the determination of Local Resource Adequacy Requirements, the same proxy units may be added to the import-constrained zone or elsewhere in the rest of the New England Control Area depending on where system constraints exist.

III.12.7.2. Capacity.

The resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall include:

- (a) all Existing Generating Capacity Resources,
- (b) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,
- (c) all Existing Import Capacity Resources backed by a multiyear contract to provide capacity in the New England Control Area, where that multiyear contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and
- (d) Existing Demand Capacity Resources that are qualified to participate in the Forward Capacity Market and New Demand Capacity Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

but shall exclude:

- (e) capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,
- (f) capacity de-listed or retired as a result of Permanent De-List Bids or Retirement De-List Bids in previous Forward Capacity Auctions, and
- (g) capacity retired pursuant to Section III.13.1.2.4.1(a), unless the Lead Market Participant has opted to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1.

The rating of Existing Generating Capacity Resources and Existing Import Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be the summer Qualified Capacity value of such resources for the relevant zone. The rating of Demand Capacity Resources shall be the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value. The rating of resources, except for Demand Capacity Resources, cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period shall be

based on the amount of Qualified Capacity that cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period. Resources are located within the Capacity Zones in which they are electrically connected as determined during the qualification process.

III.12.7.2.1. [Reserved.]

III.12.7.3. Resource Availability.

The Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated taking resource availability into account and shall be determined as follows:

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The most recent five-year moving average of EFORd shall be used as the measure of resource availability for non-peaking resources used in the calculation of Transmission Security Analysis Requirements. A deterministic adjustment factor, based on the operational experience of the ISO, shall be used as the measure of resource availability for peaking resources used in the calculation of Transmission Security Analysis Requirements, and will be reviewed periodically.

(b) [Reserved.]

(c) Once sufficient data are collected under the availability incentives in the Forward Capacity Market, a resource availability metric, which reflects resource availability in a manner that is consistent with the availability incentives in the Forward Capacity Market, shall be developed and reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies and used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

For resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that do not have sufficient data to calculate an availability metric as defined in subsections (a) or (c) above, class average data for similar resource types shall be used. For Demand Capacity Resources, historical performance data for those resources will be used to develop an

availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

III.12.7.4. Load and Capacity Relief.

Load and capacity relief expected from system-wide implementation of the following actions specified in ISO New England Operating Procedure No. 4. Action During a Capacity Deficiency, shall be included in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values:

(a) **Implement voltage reduction.** The MW value of the load relief shall be equal to the percentage load reduction achieved in the most applicable voltage reduction tests multiplied by the forecasted seasonal peak loads.

(b) **Arrange for available Emergency energy from Market Participants or neighboring Control Areas.** These actions are included in the calculation through the use of tie benefits to meet system needs. The MW value of tie benefits is calculated in accordance with Section III.12.9.

(c) **Maintain an adequate amount of ten-minute synchronized reserves.** The amount of system reserves included in the determination of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be consistent with those needed for reliable system operations during Emergency Conditions. When modeling transmission constraints, the reserve requirement for a zone shall be the zone's pro rata share of the forecasted system peak load multiplied by the system reserves needed for reliable system operations during Emergency Conditions.

III.12.8. Load Modeling Assumptions.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias. Demand Capacity Resources shall be reflected in the load forecast as specified below:

(a) Expected reductions from an installed or forecast Demand Capacity Resource not qualifying for or not participating in the Forward Capacity Auction shall be reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period. The expected reduction from these resources will be included in the load forecast to the extent that they meet the qualification process rules, including monitoring and verification plan and financial assurance requirements. If no qualification process rules are in place for the expected reductions from these resources, they shall not be included within the load forecast.

(b) Expected reductions from an installed or forecast Demand Capacity Resource that qualifies to participate in the Forward Capacity Market, participates but does not clear in the Forward Capacity Auction, or has cleared in a previous Forward Capacity Auction and is expected to continue in the Forward Capacity Market shall not be reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period.

(c) [Reserved.]

(d) Any realized Demand Capacity Resource reductions in the historical period that received Forward Capacity Market payments for these reductions, or Demand Capacity Resource reductions that are expected to receive Forward Capacity Market payments by participating in the upcoming Forward Capacity Auction or having cleared in a previous Forward Capacity Auction, shall be added back into the appropriate historical loads to ensure that such resources are not reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period.

III.12.9. Tie Benefits.

The Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated assuming appropriate tie benefits, if any, available from interconnections with neighboring Control Areas. Tie benefits shall be calculated only for interconnections (1) without Capacity Network Import Interconnection Service or Network Import Interconnection Service or (2) that have not requested Capacity Network Import Interconnection Service

or Network Import Interconnection Service with directly interconnected neighboring Control Areas with which the ISO has in effect agreements providing for emergency support to New England, including but not limited to inter-Control Area coordination agreements, emergency aid agreements and the NPCC Regional Reliability Plan.

Tie benefits shall be calculated using a probabilistic multi-area reliability model, by comparing the LOLE for the New England system before and after interconnecting the system to the neighboring Control Areas. To quantify tie benefits, firm capacity equivalents shall be added until the LOLE of the isolated New England Control Area is equal to the LOLE of the interconnected New England Control Area.

III.12.9.1. Overview of Tie Benefits Calculation Procedure.

III.12.9.1.1. Tie Benefits Calculation for the Forward Capacity Auction and Annual Reconfiguration Auctions; Modeling Assumptions and Simulation Program.

For each Capacity Commitment Period, tie benefits shall be calculated for the Forward Capacity Auction and the third annual reconfiguration auction using the calculation methodology in this Section III.12.9. For the first and second annual reconfiguration auctions for a Capacity Commitment Period, the tie benefits calculated for the associated Forward Capacity Auction shall be utilized in determining the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values as adjusted to account for any changes in import capability of interconnections with neighboring Control Areas and changes in import capacity resources using the methodologies in Section III.12.9.6.

Tie benefits shall be calculated using the modeling assumptions developed in accordance with Section III.12.9.2 and using the General Electric Multi-area Reliability Simulation (MARS) program.

III.12.9.1.2. Tie Benefits Calculation.

The total tie benefits to New England from all directly interconnected neighboring Control Areas are calculated first using the methodology in Section III.12.9.3. Following the calculation of total tie benefits, individual tie benefits from each qualifying neighboring Control Area are calculated using the methodology in Section III.12.9.4.1. If the sum of the tie benefits from each Control Area does not equal the total tie benefits to New England, then each Control Area's tie benefits are adjusted based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits calculated for each Control Area using the methodology in Section III.12.9.4.2. Following this calculation, tie benefits are calculated for

each qualifying individual interconnection or group of interconnections using the methodology in Section III.12.9.5.1. If the sum of the tie benefits from individual interconnections or groups of interconnections does not equal their associated Control Area's tie benefits, then the tie benefits of each individual interconnection or group of interconnections is adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits within the Control Area using the methodology in Section III.12.9.5.2.

III.12.9.1.3. Adjustments to Account for Transmission Import Capability and Capacity Imports.

Once the initial calculation of tie benefits is performed, the tie benefits for each individual interconnection or group of interconnections is adjusted to account for capacity imports and any changes in the import capability of interconnections with neighboring Control Areas, using the methodologies in Section III.12.9.6. Once the import capability and capacity import adjustments are completed, the sum of the tie benefits of all individual interconnections and groups of interconnections for a Control Area, with the import capability and capacity import adjustments, represents the tie benefits associated with that Control Area, and the sum of the tie benefits from all Control Areas, with the import capability and capacity import adjustments, represents the total tie benefits available to New England.

III.12.9.2. Modeling Assumptions and Procedures for the Tie Benefits Calculation.

III.12.9.2.1. Assumptions Regarding System Conditions.

In calculating tie benefits, "at criterion" system conditions shall be used to model the New England Control Area and all interconnected Control Areas.

III.12.9.2.2. Modeling Internal Transmission Constraints in New England.

In calculating tie benefits, all New England internal transmission constraints that (i) are modeled in the most recent Regional System Plan resource adequacy studies and assessments and (ii) are not addressed by either a Local Sourcing Requirement or a Maximum Capacity Limit calculation shall be modeled, using the procedures in Section III.12.9.2.5.

III.12.9.2.3. Modeling Transmission Constraints in Neighboring Control Areas.

The ISO will review annually NPCC's assumptions regarding transmission constraints in all directly interconnected neighboring Control Areas that are modeled for the tie benefits calculations. In the event that NPCC models a transmission constraint in one of the modeled neighboring Control Areas, the ISO

will perform an evaluation to determine which interfaces are most critical to the ability of the neighboring Control Area to reliably provide tie benefits to New England from both operational and planning perspectives, and will model those transmission constraints in the tie benefits calculation, using the procedures in Section III.12.9.2.5.

III.12.9.2.4. Other Modeling Assumptions.

- A.** External transfer capability determinations. The transfer capability of all external interconnections with New England will be determined using studies that take account of the load, resource and other electrical system conditions that are consistent with those expected during the Capacity Commitment Period for which the calculation is being performed. Transfer capability studies will be performed using simulations that consider the contingencies enumerated in sub-section (iii) below.
- (i) The transmission system will be modeled using the following conditions:
 1. The forecast 90/10 peak load conditions for the Capacity Commitment Period;
 2. Qualified Existing Generating Capacity Resources reflecting their output at their Capacity Network Resource level;
 3. Qualified Existing Demand Capacity Resources reflecting their Capacity Supply Obligation received in the most recent Forward Capacity Auction;
 4. Transfers on the transmission system that impact the transfer capability of the interconnection under study.
 - (ii) The system will be modeled in a manner that reflects the design of the interconnection. If an interconnection and its supporting system upgrades were designed to provide incremental capacity into the New England Control Area, simulations will assume imports up to the level that the interconnection was designed to support. If the interconnection was not designed to be so comparably integrated, simulations will determine the amount of power that can be delivered into New England over the interconnection.
 - (iii) The simulations will take into account contingencies that address a fault on a generator or transmission facility, loss of an element without a fault, and circuit breaker failure following the loss of an element or an association with the operation of a special protection system.

- B.** In calculating tie benefits, New England capacity exports are removed from the internal capacity resources and are modeled as a resource in the receiving Control Area. The transfer capability of external interconnections is not adjusted to account for capacity exports.

III.12.9.2.5. Procedures for Adding or Removing Capacity from Control Areas to Meet the 0.1 Days Per Year LOLE Standard.

In calculating tie benefits, capacity shall be added or removed from the interconnected system of New England and its neighboring Control Areas, until the LOLE of New England and the LOLE of each Control Area of the interconnected system equals 0.1 days per year simultaneously. The following procedures shall be used to add or remove capacity within New England and the interconnected Control Areas to achieve that goal.

- A. Adding Proxy Units within New England when the New England system is short of capacity.** In modeling New England as part of the interconnected system, if New England is short of capacity to meet the 0.1 days per year LOLE, proxy units (with the characteristics identified in Section III.12.7.1) will be added to the sub-areas that are created by any modeled internal transmission constraints within New England, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the New England Control Area, then proxy units will be added to the entire Control Area. If, as a result of the addition of one or more proxy units, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(b) will be used to remove the surplus capacity.
- B. Removing capacity from New England when the New England system is surplus of capacity.** In modeling New England as part of the interconnected system, if New England is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in these surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the Existing Qualified Capacity, and any amount of proxy units added in that sub-area that is above its 50-50 peak load forecast. Notwithstanding the foregoing, if removing resources will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratios described above for the removal of capacity surplus. If there are no modeled internal transmission constraints in the New England Control Area, then the surplus capacity shall be removed from the entire Control Area.

- C. Adding capacity within neighboring Control Areas when the neighboring Control Area is short of capacity.** In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is short of capacity to meet the 0.1 days per year LOLE, additional capacity will be added to the neighboring Control Area's sub-areas that are created by any modeled internal transmissions constraints, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the Control Area, then capacity will be added to the entire Control Area. The process that the neighboring Control Area utilizes in its resource adequacy study to meet its resource adequacy criterion will be utilized to add capacity to that Control Area. In filing the Installed Capacity Requirement values pursuant to Section III.12.3, the ISO will provide citations to any resource adequacy studies relied upon for these purposes. If, as a result of the capacity addition, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(d) shall be used to remove the surplus capacity.
- D. Removing capacity from neighboring Control Areas when the neighboring Control Area is surplus of capacity.** In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the neighboring Control Area's sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in the surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the installed capacity in the sub-area above its 50/50 peak load forecast. For a sub-area that has a minimum locational resource requirement above its 50/50 peak load forecast, the amount of capacity surplus is the amount of the installed capacity in the sub-area above its minimum locational resource requirement. Notwithstanding the foregoing, if removing resources from a sub-area will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratio of capacity surplus in the sub-area to the total capacity surplus in the those remaining surplus sub-areas. If there are no modeled internal transmission constraints in the neighboring Control Area, then the surplus capacity will be removed from the entire Control Area.
- E. Maintaining the neighboring Control Area's locational resource requirements.** In modeling a neighboring Control Area with internal transmission constraints, all minimum locational resource requirements in the Control Area's sub-areas as established by the neighboring Control Area's installed capacity requirement calculations shall be observed.

III.12.9.3. Calculating Total Tie Benefits.

The total tie benefits with all qualifying directly interconnected neighboring Control Areas shall be calculated by comparing the interconnection state of the New England system with all interconnections to neighboring Control Areas connected with the interconnection state of the New England system with all interconnections with neighboring Control Areas disconnected. To calculate total tie benefits:

- A.** The New England system shall be interconnected with all directly interconnected neighboring Control Areas and the New England Control Area, and each neighboring Control Area shall be brought to 0.1 days per year LOLE simultaneously by adjusting the capacity of each Control Area, utilizing the methods for adding or removing capacity in Section III.12.9.2.5.
- B.** Once the interconnected system is brought to 0.1 days per year LOLE, the LOLE of the New England Control Area shall be calculated a second time, with the New England system isolated from the rest of the interconnected system that was brought to 0.1 days per year LOLE.
- C.** Total tie benefits shall be the sum of the amounts of firm capacity that needs to be added to the isolated New England Control Area at the point at which each interconnection with neighboring Control Areas interconnects in New England to bring the New England LOLE back to 0.1 days per year. This value is subject to adjustment in accordance with Section III.12.9.6.

III.12.9.4. Calculating Each Control Area's Tie Benefits.

III.12.9.4.1. Initial Calculation of a Control Area's Tie Benefits.

Tie benefits from each neighboring Control Area shall be determined by calculating the tie benefits for every possible interconnection state that has an impact on the tie benefit value between the New England system and the target neighboring Control Area. If two or more interconnections between New England and the target neighboring Control Area exist, then all interconnections grouped together will be used to represent the state of interconnection between New England and the target neighboring Control Area. The tie benefits from the target neighboring Control Area shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.4.2.

III.12.9.4.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual Control Area tie benefits calculated in accordance with Section III.12.9.4.1 is different than the total tie benefits from all Control Areas calculated in accordance with Section III.12.9.3, then each Control Area's tie benefits shall be increased or decreased based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits for each individual Control Area, so that the sum of each Control Area's tie benefits, after the pro-ration, is equal to the total tie benefits calculated in accordance with Section III.12.9.3. The pro-rated Control Area tie benefits are subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.5. Calculating Tie Benefits for Individual Ties.

Tie benefits shall be calculated for an individual interconnection or group of interconnections to the extent that a discrete and material transfer capability can be identified for the interconnection or group of interconnections. All interconnections or groups of interconnections shall have equal rights in calculating individual tie benefits, with no grandfathering or incremental tie capability treatment.

For purposes of calculating tie benefits, a group of interconnections refers to two or more AC lines that operate in parallel to form a transmission interface in which there are significant overlapping contributions of each line toward establishing the transfer limit, such that the individual lines in a group of interconnections cannot be assigned individual contributions.

III.12.9.5.1. Initial Calculation of Tie Benefits for an Individual Interconnection or Group of Interconnections.

Tie benefits for an individual interconnection or group of interconnections shall be calculated by calculating tie benefits for each possible interconnection state between the New England system and the individual interconnection or group of interconnections. The tie benefits from that interconnection or group of interconnections shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.5.2.

III.12.9.5.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual interconnection's or group of interconnection's tie benefits calculated in accordance with Section III.12.9.5.1 is different than the associated Control Area's tie benefits calculated in accordance with Section III.12.9.4, then the tie benefits of the individual interconnection or group of interconnections shall be adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits for each interconnection or group of interconnections in that Control Area, so that the sum of the tie benefits for each interconnection or group

of interconnections in the Control Area, after the pro-ration, is equal to the total tie benefits for the Control Area calculated in accordance with Section III.12.9.4. The pro-rated tie benefits for each interconnection or group of interconnections is subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.6. Accounting for Capacity Imports and Changes in External Transmission Facility Import Capability.

III.12.9.6.1. Accounting for Capacity Imports.

In the initial tie benefits calculations, capacity imports are modeled as internal resources in New England, and the import capability of the interconnections with neighboring Control Areas is not reduced to reflect the impact of capacity imports. After the initial tie benefits calculations, total tie benefits, tie benefits for each Control Area, and tie benefits from each individual interconnection or group of interconnections shall be adjusted to account for capacity imports using the methodology contained in this Section III.12.9.6.1. For the Forward Capacity Auction and third annual reconfiguration auction, this adjustment shall be applied to the tie benefit values calculated in accordance with Sections III.12.9.3, III.12.9.4 and III.12.9.5 respectively. For the first and second annual reconfiguration auctions, this adjustment shall be applied to the tie benefits values calculated for the Forward Capacity Auction.

- A.** Capacity imports shall be deducted from the import capability of each individual interconnection or group of interconnections to determine the available import capability of the interconnection or group of interconnections prior to accounting for tie benefits from those interconnections. The transfer capability of an interconnection or group of interconnections shall be determined using the procedures in Section III.12.9.2.4.A.
- B.** If the tie benefits value of an individual interconnection or group of interconnections, as determined in accordance with Section III.12.9.5, is greater than the remaining transmission import capability of the interconnection or group of interconnections after accounting for capacity imports, the tie benefit value of the individual interconnection or group of interconnections shall be equal to the remaining transmission import capability (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2). If the tie benefits value of an individual interconnection or group of interconnections is not greater than the remaining transmission import capability after accounting for capacity imports, then the tie benefit value of the individual interconnection or group of interconnections shall be equal to the value determined in accordance with Section

- III.12.9.5 (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2).
- C. The tie benefits for each Control Area shall be the sum of the tie benefits from the individual interconnections or groups of interconnections with that Control Area, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.
 - D. The total tie benefits from all qualifying neighboring Control Areas shall be the sum of the Control Area tie benefits, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.
 - E. For purposes of determining the adjustment to tie benefits to account for capacity imports under this Section III.12.9.6.1, the capacity imports applicable for determining tie benefits for the Forward Capacity Auction shall be the Qualified Existing Import Capacity Resources for the relevant Capacity Commitment Period, and the capacity imports applicable for determining tie benefits for the annual reconfiguration auctions are those Import Capacity Resources that hold Capacity Supply Obligations for the relevant Capacity Commitment Period as of the time the tie benefits calculation is being performed for the annual reconfiguration auction.

III.12.9.6.2. Changes in the Import Capability of Interconnections with Neighboring Control Areas.

For purposes of calculating tie benefits for the Forward Capacity Auction and third annual reconfiguration auction, the most recent import capability values for an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the modeling of system conditions for the tie benefits calculation. In addition, for the first and second annual reconfiguration auctions, any changes to the import capability of an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the adjustment to tie benefits to account for capacity imports under Section III.12.9.6.1.

III.12.9.7. Tie Benefits Over the HQ Phase I/II HVDC-TF.

The tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1 shall be allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.

III.12.10. Calculating the Maximum Amount of Import Capacity Resources that May be Cleared Over External Interfaces in the Forward Capacity Auction and Reconfiguration Auctions.

For external interfaces, Import Capacity Resources shall be allowed in the Forward Capacity Auction and reconfiguration auctions up to the interface limit minus the tie benefits, calculated pursuant to Section III.12.9.1 or 12.9.2 over the applicable interface.

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 Capacity Resource or Existing Demand Capacity 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 Capacity Resource, New Generating Capacity Resource, New Import Capacity Resource, and New Demand Capacity Resource.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the FCM Deposit.

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 Capacity Resource or Existing Demand Capacity 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.13.1.1.3 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.13.1.1.3.A. Treatment of New Incremental Capacity and Existing Generating Capacity at the Same Generating Resource.

For incremental summer capacity seeking to participate in the Forward Capacity Auction pursuant to Section III.13.1.1.3 or incremental winter capacity that meets the investment thresholds in Section III.13.1.1.3 as applied to the resource's winter Qualified Capacity, if the incremental summer or winter capacity does not span the entire Capacity Commitment Period, then the ISO shall match the incremental summer or winter capacity with excess existing winter or summer Qualified Capacity at that same resource, as appropriate, not to exceed the Qualified Capacity of the existing portion of the resource, in order to cover the entire Capacity Commitment Period. This provision shall not apply to Intermittent Power Resources or Intermittent Settlement Only Resources.

III.13.1.1.4. 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 15 Business Days before the Existing Capacity Retirement 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 or an On-Peak Demand Resource (including every Asset that is part of the On-Peak Demand 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 or New Demand 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, or in the case of an Import Capacity Resource seeking to qualify with an Elective Transmission Upgrade be associated with, an Interconnection Request under Schedules 22, 23 or 25 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 interconnection procedures described in Schedules 22, 23 and 25 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 FCM 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. 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, 23 and 25 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 Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23, or Section 4.4 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein or the New Capacity Show of Interest Form 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, 23 and 25 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 interconnection procedures described in Schedules 22, 23 and 25 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, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff. In the case of a resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource that is supported by an Internal Elective Transmission Upgrade, all Queue Positions associated with the project must be submitted in the New Capacity Show of Interest Form. 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 pursuant to Section III.13.1.1.2.2.1.

(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 achieve, prior to the close of the New Capacity Show of Interest Submission Window, control of the project site for the duration of the relevant Capacity Commitment Period, which shall be as defined in Section 4.1 of Schedule 22, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

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. For an Import Capacity Resource associated with an Elective Transmission Upgrade that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, major components shall also include, to the extent applicable, transmission facilities and associated substation equipment.

(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 of Section II of the Transmission, Markets and Services Tariff.

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. For incremental capacity qualified pursuant to Section III.13.1.1.1.3.A, this election shall apply to both the incremental amount of capacity and the existing Qualified Capacity matched to the incremental capacity at the same generating resource. 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 Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23 and Section 4.4 of Schedule 25 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 or Capacity Network Import Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22, 23 and 25 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) or Elective Transmission Upgrade Interconnection Customer 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) or Elective Transmission Upgrade Interconnection Customer, 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, 23 and 25 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 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, Section 1.7.1.3 of Schedule 23, or Section 3.2.1.3 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff 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(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 Resource; (ii) for the notification to a Conditional Qualified New 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 Resource, the Queue Position of the Conditional Qualified New 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 or New Demand 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 or Section III.13.1.4.1.1.6. 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.

The submission of a Renewable Technology Resource election that satisfies the requirements of Section III.13.1.1.1.7 will invalidate a prior multi-year Capacity Supply Obligation and Capacity Clearing Price election for the same resource made pursuant to Section III.13.1.4.1.1.2.7 or Section III.13.1.1.2.2.4 for a Forward Capacity Auction.

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 Capacity Resource or Existing Demand Capacity 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.

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 there was a system-wide Capacity Scarcity Condition and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions 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(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 there was a system-wide Capacity Scarcity Condition and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions 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 Retirement 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 Retirement 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 the close of the New Capacity Show of Interest Submission Window. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction meets the requirements of this Section, but the incremental amount of capacity does not span the entire Capacity Commitment Period, then the ISO shall match the incremental amount of capacity with excess Qualified Capacity at that same resource, not to exceed the Qualified Capacity of the existing portion of the resource, in order to cover the entire Capacity Commitment Period. This provision shall not apply to Intermittent Power Resources or Intermittent Settlement Only Resources.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Capacity Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Capacity 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 20 Business Days before the Existing Capacity Retirement 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 10 Business Days before the Existing Capacity Retirement Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, a Permanent De-List Bid, or a Retirement 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 Retirement Package and Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant to 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 15 Business Days before the Existing Capacity Retirement Deadline, as described in Section III.13.1.1.1.6(b). All Permanent De-List Bids and Retirement De-List Bids in the Forward Capacity

Auction must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline. All Static De-List Bids, Export Bids and Administrative Export 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. Permanent De-List Bids and Retirement De-List Bids may not be modified or withdrawn after the Existing Capacity Retirement Deadline, except as provided for in Section III.13.1.2.4.1. All Static 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, except as provided for in Section III.13.1.2.3.1.1. An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Permanent De-List Bid, or Retirement De-List Bid for an amount of capacity greater than its summer Qualified Capacity, unless the submittal is for the entire resource. Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 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; neither a Permanent De-List Bid nor a Retirement De-List Bid may be combined with any other type of de-list or export bid.

Static De-List Bids and Export 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 for a Forward Capacity Auction is \$5.50/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.

III.13.1.2.3.1.1. Static De-List Bids.

A Lead Market Participant with an Existing Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation for that resource, or a portion thereof, 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 qualification process. 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). 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 Lead Market Participant must notify the ISO if the Existing Capacity Resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests).

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b), a Lead Market Participant that submitted a Static De-List Bid may: (a) lower the price of any price-quantity pair of a Static De-List Bid, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or; (b) withdraw any price-quantity pair of a Static De-List Bid.

III.13.1.2.3.1.2. [Reserved.]

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 qualification process. 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 at or 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 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 qualification process. 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 shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Permanent De-List Bids and Retirement De-List Bids.

(a) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would not accept a Capacity Supply Obligation permanently for all or part of a Generating Capacity Resource beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction qualification process.

(b) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would retire all or part of a Generating Capacity Resource from all New England Markets beginning at the start of a particular Capacity Commitment Period may submit a Retirement De-List Bid in the associated Forward Capacity Auction qualification process.

(c) No Permanent De-List Bid or Retirement De-List Bid may result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit unless the Permanent De-List Bid or Retirement De-List Bid is for the entire resource. Each Permanent De-List Bid and Retirement De-List Bid must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Permanent De-List Bids and Retirement De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2.1 and must include the additional documentation described in that section. Once submitted, no Permanent De-List Bid or Retirement De-List Bid may be withdrawn, except as provided in Section III.13.1.2.4.1.

III.13.1.2.3.1.5.1. Reliability Review of Permanent De-List Bids and Retirement De-List Bids During the Qualification Process.

During the qualification process, the ISO will review the following de-list bids to determine if the resource is needed for reliability: (1) Internal Market Monitor-accepted Permanent De-List Bids and Internal Market Monitor- accepted Retirement De-List Bids that are at or above the Forward Capacity Auction Starting Price; and (2) Permanent De-List Bids and Retirement De-List Bids for which the Lead

Market Participant has opted to have the resource reviewed for reliability as described in Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b). The reliability review will be conducted according to Section III.13.2.5.2.5, except as follows:

(a) Permanent De-List Bids and Retirement De-List Bids that cannot be priced (for example, due to the expiration of an operating license) will be reviewed first.

(b) System needs associated with Permanent De-List Bids and Retirement De-List Bids for resources found needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1 will be reviewed with the Reliability Committee no later than 30 days after the ISO submits to the Commission the retirement filing described in Section III.13.8.1(a). The Lead Market Participant shall be notified as soon as practicable following the ISO's consultation with the Reliability Committee that the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons.

(c) If the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1, the de-list bid shall be rejected and the resource shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(c) and compensated according to Section III.13.2.5.2.5, unless the resource declines to be retained for reliability, as provided in Section III.13.1.2.3.1.5.1(d).

(d) No later than 10 Business Days after being informed that a resource is needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1, a Lead Market Participant may notify the ISO that it declines to provide the associated capacity for reliability. Such an election will be binding. A resource for which a Lead Market Participant has made such an election will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2.

(e) Where a resource is determined not to be needed for reliability or where a Lead Market Participant notifies the ISO that it declines to provide capacity for reliability pursuant to Section III.13.1.2.3.1.5.1(d), the capacity associated with the Permanent De-List Bid or Retirement De-List Bid will be treated as follows:

(i) For a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has

elected to retire the resource pursuant to Section III.13.1.2.4.1(a), the portion of the resource subject to the de-list bid will be retired as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(a).

(ii) For a Permanent De-List Bid at or above the Forward Capacity Auction Starting Price, the portion of the resource subject to the de-list bid will be permanently de-listed coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(b).

(iii) For a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the de-list bid will be continue to receive conditional treatment as described in Section III.13.1.2.4.1(b), Section III.13.2.3.2(b)(ii), and Section III.13.2.5.2.1.

III.13.1.2.3.1.6. Static De-List Bids, Permanent De-List Bids and Retirement 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, Permanent De-List Bids, or Retirement 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, Permanent De-List Bids, or Retirement 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 of Stations having Common Costs.

The Internal Market Monitor will review each Static De-List Bid, Permanent De-List Bid and Retirement De-List Bids 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 establish an Internal Market Monitor-determined or Internal Market Monitor-accepted price for the bid as described in Section III.13.1.2.3.2.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Capacity Resources.

The Internal Market Monitor shall review bids for Existing Capacity Resources as follows.

III.13.1.2.3.2.1. Static De-List Bids and Export Bids, Permanent De-List Bids, and Retirement De-List Bids at or Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid and each Export Bid at or above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the Existing Capacity Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2.A); (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).

The Internal Market Monitor shall review each Permanent De-List Bid greater than 20 MW that is above the Dynamic De-List Bid Threshold and each Retirement De-List Bid greater than 20 MW that is above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the net present value of the resource's expected cash flows (as determined pursuant to Section III.13.1.2.3.2.1.2.B); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); and (3) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). If more than one Permanent De-List Bid or Retirement De-List Bid is submitted by a single Lead Market Participant or its Affiliates (as used in Section III.A.24), the Internal Market Monitor shall review each such bid above the Dynamic De-List Bid Threshold if the sum of all such bids above the Dynamic De-List Bid Threshold is greater than 20 MW. The Internal Market Monitor shall review each Permanent De-List Bid and each Retirement De-List Bid submitted at any price pursuant to Section III.13.2.5.2.1(b) if the sum of the Permanent De-List Bids and Retirement De-List Bids submitted by the Lead Market Participant or its Affiliates (as used in Section III.A.24) is greater than 20 MW. Permanent De-List Bids and Retirement De-List Bids that are not reviewed by the Internal Market Monitor shall be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

Sufficient documentation and information about each bid component must be included in the Existing Capacity Retirement Package or the Existing Capacity Qualification Package to allow the Internal Market Monitor to make the requisite determinations. If a Permanent De-List Bid or Retirement De-List Bid is submitted pursuant to Section III.13.2.5.2.1(b), all relevant updates to previously submitted documentation and information must be provided to support the newly submitted price and allow the Internal Market Monitor to make updated determinations. The updated information may include a request to discontinue the Permanent De-List Bid or Retirement De-List Bid such that it will not be entered into the Forward Capacity Auction, in which case the update must include sufficient supporting information on the nature of resource investments that were undertaken, or other materially changed circumstances, to allow the Internal Market Monitor to determine whether discontinuation is appropriate.

The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of its content, including 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, cash flows, opportunity costs, 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 Static De-List Bids and Export Bids.

If the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that a Static De-List Bid or an Export Bid is not consistent with the sum of the

resource's net going forward costs plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable risk premium assumptions plus reasonable opportunity costs, then the Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid that is consistent with its determination of the foregoing. If an Internal Market Monitor-determined price is established for a Static De-List Bid or an Export Bid, 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(c) shall include an explanation of the Internal Market Monitor-determined price 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.

III.13.1.2.3.2.1.1.2. Review of Permanent De-List Bids and Retirement De-List Bids.

The Internal Market Monitor shall review those Permanent De-List Bids and Retirement De-List Bids identified in Section III.13.1.2.3.2.1 and, after due consideration and consultation with the Lead Market Participant, as appropriate, shall develop an Internal Market Monitor-accepted Permanent De-List Bid or an Internal Market Monitor-accepted Retirement De-List Bid. The Internal Market Monitor-accepted Permanent De-List Bid and Internal Market Monitor-accepted Retirement De-List Bid shall be equal to the Permanent De-List Bid or Retirement De-List Bid submitted by the Lead Market Participant unless the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s) for the same de-list bid. If the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s), the Internal Market Monitor shall calculate an Internal Market Monitor-accepted Permanent De-List Bid or Internal Market-Monitor-accepted Retirement De-List Bid that is consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The retirement determination notification described in Section III.13.1.2.4(a) and the filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the Internal Market Monitor-accepted price and the Internal Market Monitor determination on any request to discontinue the Permanent De-List Bid or Retirement De-List Bid.

III.13.1.2.3.2.1.2.A. Static De-List Bid and Export Bid Net Going Forward Costs.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an Export Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net going forward costs in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. A Static De-List Bid or Export Bid at or above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing 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 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 that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period. 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.

$CQ_{\text{Summer,kW}}$ = 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 that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, 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 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. $\text{infIndex} = (1 + i)^4$

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.13.1.2.3.2.1.2.B Permanent De-List Bid and Retirement De-List Bid Net Present Value of Expected Cash Flows.

The Lead Market Participant for an Existing Capacity Resource that submits a Permanent De-List Bid or

Retirement De-List Bid that is to be reviewed by the Internal Market Monitor shall report all expected costs, revenues, prices, discount rates and capital expenditures in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. The Internal Market Monitor will review the Lead Market Participant's submitted data to ensure that it is consistent with overall market conditions and reflects expected values.

The Internal Market Monitor will adjust any data that are inconsistent with overall market conditions or do not reflect expected values. The Internal Market Monitor shall enter all relevant expected costs, revenues, prices, discount rates and capital expenditures into a capital budgeting model and shall determine the net present value of the Existing Capacity Resource's expected cash flows as follows:

The net present value of the Existing Capacity Resource's expected cash flows is equal to (i) the net present value of the Existing Capacity Resource's net annual expected cash flows over the resource's remaining economic life (as determined pursuant to Section III.13.1.2.3.2.1.2.C) plus the net present value of the resource's expected terminal value, using the resource's discount rate, divided by (ii) the product of the resource's Qualified Capacity (in kilowatts) and 12 months.

The Existing Capacity Resource's net annual expected cash flow for the first Capacity Commitment Period of the resource's remaining economic life is the resource's expected annual net operating profit excluding expected capacity revenues less its expected capital expenditures in the Capacity Commitment Period.

The Existing Capacity Resource's net annual expected cash flow for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life is the resource's expected annual net operating profit less its expected capital expenditures in the Capacity Commitment Period.

Where:

Expected net operating profit, in dollars, is the Lead Market Participant's expected annual profit that might otherwise be avoided or not accrued if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period. Expected labor, maintenance, taxes, insurance, administrative and other normal expenses that can be avoided or not incurred if the resource is retired or permanently de-listed may be included. Service of debt is not an avoidable cost and may not be

included.

Expected capacity revenues, in dollars, are the forecasted annual expected capacity revenues based on the Lead Market Participant's forecasted expected capacity prices for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life. The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the forecasted expected capacity prices. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions about expected resource additions, resource retirements, estimated Installed Capacity Requirements, estimated Local Sourcing Requirements, expected market conditions, and any other assumptions used to develop the forecasted expected capacity price in each Capacity Commitment Period.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the forecasted expected capacity prices, the Internal Market Monitor will replace the Lead Market Participant's forecasted expected capacity prices with the Internal Market Monitor's estimate thereof in each of the subsequent Capacity Commitment Periods of the resource's remaining economic life.

Expected capital expenditures, in dollars, are the Lead Market Participant's expected capital investments 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 Periods.

Expected terminal value, in dollars, for resources with five years or less of remaining economic life, is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource. For resources with more than five years of remaining economic life, the expected terminal value in the fifth year of the evaluation period is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource at the end of the resource's economic life plus the net present value of the Existing Capacity Resource's net annual expected cash flows from the sixth year of the evaluation period through the end of the resource's remaining economic life, using the resource's discount rate.

Discount rate is a value reflecting the Lead Market Participant's weighted average cost of capital for the Existing Capacity Resource adjusted to reflect the risk to cash flows calculated pursuant to the net present

value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B.

The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.

The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions associated with the cost of capital, risks and any other assumptions used to develop the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the weighted average cost of capital for the Existing Capacity Resource adjusted for risk, the Lead Market Participant has included risks not associated with cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B or the Lead Market Participant has submitted costs, revenues, capital expenditures or prices that are not reflective of expected values, the Internal Market Monitor will replace the Lead Market Participant's discount rate with a value determined by the Internal Market Monitor.

III.13.1.2.3.2.1.2.C Permanent De-List Bid and Retirement De-List Bid Calculation of Remaining Economic Life.

The Internal Market Monitor shall calculate the Existing Capacity Resource's remaining economic life, using evaluation periods ranging from one to five years. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the Capacity Clearing Price for the first year is equal to the Forward Capacity Auction Starting Price and (b) the expected terminal value of the resource at the end of the given evaluation period. The economic life is the maximum evaluation period in which a resource's net present value is non-negative.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an Export Bid, Permanent De-List Bid, or Retirement De-List Bid at or 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 Capacity Resource that submits a Static De-List Bid, or an Export Bid at or 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.A 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 Capacity Resource submitting a Static De-List Bid or an Export Bid, Permanent De-List Bid or Retirement De-List Bid at or above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected Capacity Performance Payments, discount rate, 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. Static De-List Bid Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all Static 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:

$$\frac{\text{Cost Of Capital}}{(1 - (1 + \text{CostOfCapital})^{-\text{RemainingLife}})}$$

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. Retirement Determination Notification for Existing Capacity and Qualification Determination Notification for Existing Capacity.

(a) No later than 90 days after the Existing Capacity Retirement Deadline, the ISO shall send notification to the Lead Market Participant that submitted each Permanent De-List Bid and Retirement De-List Bid concerning the result of the Internal Market Monitor's review conducted pursuant to Section III.13.1.2.3.2. This retirement determination notification shall not include the results of the reliability review pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5.

(b) 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 and Export Bid concerning the result of the Internal Market Monitor's de-list bid review conducted pursuant to Section III.13.1.2.3.2. The qualification determination shall not include the results of the reliability review pursuant to Section III.13.2.5.2.5.

III.13.1.2.4.1. Participant-Elected Retirement or Conditional Treatment.

No later than ten Business Days after the issuance by the ISO of the retirement determination notification described in Section III.13.1.2.4(a), a Lead Market Participant that submitted a Permanent De-List Bid or Retirement De-List Bid may make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b). If the Lead Market Participant does not make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b), the prices provided by the Internal Market Monitor in the retirement determination notifications shall be the finalized prices used in the Forward Capacity Auction as described in Section III.13.2.3.2(b) (unless otherwise directed by the Commission).

(a) A Lead Market Participant may elect to retire the resource, or portion thereof, for which it has submitted a Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will not be subject to reliability review and will be retired pursuant to Section III.13.2.5.2.5.3(a); provided, however, that when making the retirement election pursuant to this Section III.13.1.2.4.1(a) the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

(b) A Lead Market Participant may elect conditional treatment for the Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will be treated as described in Section III.13.2.3.2(b)(ii), Section III.13.2.5.2.1, and Section III.13.2.5.2.5.3; provided, however, that in making this election the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

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 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 established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff.

An Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be included in the FCM (1) after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Forward Capacity Market qualification requirements or (2) after it has met the requirements of an Elective Transmission Upgrade with Long Lead Time Facility treatment pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff. An external node for such an Elective Transmission Upgrade will be modeled for participation in the Forward Capacity Market after the Import Capacity Resource meets the requirements to participate in the FCA. The Qualified Capacity of an Import Capacity Resource associated with an Elective Transmission Upgrade shall not exceed the Capacity Network Import Interconnection Service Interconnection Request. In order for an Elective Transmission Upgrade to maintain its Capacity Network Import Interconnection Service, an associated Import Capacity Resource must meet the Forward Capacity Market qualification requirements and offer into each Forward Capacity Auction. Otherwise, the Capacity

Network Import Interconnection Service will revert to Network Import Interconnection Service for the portion of the Capacity Network Import Interconnection Service for which no Import Capacity Resource is offered into the Forward Capacity Auction and the Elective Transmission Upgrade's Interconnection Agreement will be revised. The provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election, shall apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade seeking to reestablish Capacity Network Import Interconnection Service if the threshold to be treated as a new resource in Section III.13.1.1.1.4 is met. If the threshold to be treated as a new increment in Section III.13.1.1.1.3 is met, only the increment will be eligible for the provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election.

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Retirement 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.A Qualification Process for Existing Import Capacity Resources that are not associated with an Elective Transmission Upgrade with Capacity Network Import Interconnection Service.

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) The Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.
- (b) The rationing election described in Section III.13.1.2.3.1 shall not apply.
- (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 15 Business Days prior to the Existing Capacity Retirement 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.13.1.3.3.B. Qualification Process for Existing Import Capacity Resources that are associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service.

Existing Import Capacity Resources associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be subject to the same qualification process as Existing Generating Capacity Resources as described in Section III.13.1.2.3, except the Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

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.

(a) For each New Import Capacity Resource, the Project Sponsor 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 the contract period including the entire Capacity Commitment Period, 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 Project Sponsor must specify the interface over which the capacity will be imported. The Project Sponsor must indicate whether the import is associated with any investment in transmission that increases New England's import capability or is associated with an Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff. The Project Sponsor must submit a contract confirming its association with the Elective Transmission Upgrade Interconnection Customer and the ISO will confirm that relationship. If the import will be backed by a single new External Resource, the Project Sponsor 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).

(b) To qualify for Capacity Commitment Periods prior to the Capacity Commitment Period associated with the Forward Capacity Auction for which the import capacity is qualifying, the Project Sponsor must submit documentation of one or more one-year contracts for each prior Capacity Commitment Period, 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(s); the Project Sponsor must also satisfy the relevant requirements of Sections III.13.1.3.5.1(a) , III.13.1.3.5.2, III.13.1.9, and III.13.3.1.1.

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 and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, 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 Project Sponsor shall instead submit a description of how the New Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets, 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 apply in addition to the requirement that the Project Sponsor submit a description of how the New Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the Project Sponsor, 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 and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, 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 Project Sponsor 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.

If the New Import Capacity Resource will be backed by an external Control Area and the capacity will be imported over an Elective Transmission Upgrade and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, 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 apply in addition to the requirement that the Project Sponsor 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 for the length of the multi-year contract.

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 Project Sponsor 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 Project Sponsor 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 Project Sponsor 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 only apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request. All other 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.

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 unless the capacity will be imported over an Elective Transmission Upgrade pursuing Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.3.5.5.A. Cost Information.

The offer information described in Section III.13.1.1.2.2.3 and Section III.A.21.2 may be submitted in the form of a curve (up to five price-quantity pairs) associated with a specific New Import Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each 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.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources.

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.

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.1.2.8, a Lead Market Participant with a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade) that submitted a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5 may: (a) lower the requested offer price of any price-quantity pair submitted to the ISO pursuant to Section III.13.1.1.2.2.3, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or (b) withdraw any price-quantity pair of a requested offer price.

III.13.1.3.5.8. Rationing Election.

New Import Capacity Resources are subject to rationing except New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request, which are eligible for the rationing election described in Section III.13.1.1.2.2.3(b).

III.13.1.4. Demand Capacity Resources.

To participate in a Forward Capacity Auction as a Demand Capacity Resource, a resource must meet the requirements of this Section III.13.1.4. Each Demand Capacity Resource shall be a minimum of 100 kW. An Active Demand Capacity Resource comprises one or more Demand Response Resources located in a single Dispatch Zone. An On-Peak Demand Resource or Seasonal Peak Demand Resource comprises one or more Assets located in a single Load Zone. Demand Capacity Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Capacity Resource. Demand Capacity Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

III.13.1.4.1. Definition of New Demand Capacity Resource.

A New Demand Capacity Resource is an Active Demand Capacity Resource that has not cleared in a previous Forward Capacity Auction, and On-Peak Demand Resource consisting of measures that have not been in service prior to the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction, or a Seasonal Peak Demand Resource consisting of measures that have not been in service prior to the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. A Demand Capacity Resource that has previously been defined as an Existing Demand Capacity Resource shall be considered a New Demand Capacity Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.1. Qualification Process for New Demand Capacity Resources.

For Forward Capacity Auctions a New Demand Capacity Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's estimated demand reduction value as submitted and reviewed pursuant to this Section III.13.1.4. The FCA Qualified Capacity for a New Demand Capacity 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.

(a) For a resource to qualify as a New Demand Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit estimated demand reduction values and supporting information in the New Demand Capacity Resource Show of Interest Form as described in Section III.13.1.4.1.1.1. Second, the Project Sponsor must submit a New Demand Capacity Resource Qualification Package as described in Section III.13.1.4.1.1.2.

(b) For a resource to qualify as a New Demand Capacity Resource that is an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Project Sponsor must in addition submit, as part of the New Demand Capacity Resource Qualification Package, a Measurement and Verification Plan providing the documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.1, 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.13.1.4.1.1.1. New Demand Capacity Resource Show of Interest Form.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource, the Project Sponsor must submit to the ISO a New Demand Capacity Resource Show of Interest Form as described in this Section III.13.1.4.1.1.1 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 Capacity Resource Show of Interest Form is available on the ISO website.

A completed New Demand Capacity Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Capacity Resource will be located; the Dispatch Zone within which an Active Demand Capacity 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 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 Capacity Resource (for an Active Demand Capacity Resource, this estimate must be consistent with the baseline calculation methodology in Section III.8.2); 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 Capacity Resource type (Active Demand Capacity Resource, On-Peak Demand Resource, or Seasonal Peak Demand Resource); brief Demand Capacity 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 Capacity Resource shall mean the demonstration to the

ISO by the Project Sponsor that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity 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 Capacity 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.13.1.4.1.1.2. New Demand Capacity Resource Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource, the Project Sponsor must submit a New Demand Capacity Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Capacity Resource Qualification Package shall conform to the requirements of this Section

III.13.1.4.1.1.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.1.1.2.1. Source of Funding.

The Project Sponsor must provide in the New Demand Capacity Resource Qualification Package the source of funding, which includes, but is not limited to, the following: the source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; and a completed ISO credit application.

III.13.1.4.1.1.2.2. Measurement and Verification Plan.

For On-Peak Demand Resources and Seasonal Peak Demand Resources, the Project Sponsor must provide in the New Demand Capacity Resource Qualification Package a Measurement and Verification Plan that complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.1.2.3. Customer Acquisition Plan.

A Project Sponsor with more than a single customer must include in the New Demand Capacity Resource Qualification Package 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.13.1.4.1.1.2.4. Critical Path Schedule for a Demand Capacity Resource with a Demand Reduction Value of at Least 5 MW at a Single Retail Delivery Point.

The Project Sponsor of a Demand Capacity Resource with a demand reduction value of at least 5 MW at a single Retail Delivery Point shall provide in the New Demand Capacity Resource Qualification Package a critical path schedule as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.1.1.2.5. Critical Path Schedule for a Demand Capacity Resource with All Retail Delivery Points Having a Demand Reduction Value of Less Than 5 MW.

The Project Sponsor of a Demand Capacity Resource with all Retail Delivery Points having a demand reduction value of less than 5 MW shall provide in the New Demand Capacity Resource Qualification Package a critical path schedule comprised of a delivery schedule of the share of total offered demand reduction value achieved as of target dates, as follows: (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 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 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.13.1.4.1.1.2.6. Additional Critical Path Schedule Requirement For Project Sponsors Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Project Sponsor proposes in its New Demand Capacity Resource Qualification Package a cumulative percentage of demand reduction value achieved 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 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 Project Sponsor's program to

deliver capacity to meet the Project Sponsor's Forward Capacity Auction obligations, and must include each customer's projected summer and winter demand reduction value, and expected measure installation date; provided, however, that a 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 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 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.13.1.4.1.1.2.7. Capacity Commitment Period Election.

In the New Demand Capacity Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Capacity 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 Capacity Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Capacity Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Capacity 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 Capacity Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Capacity 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.13.1.4.1.1.2.7.

III.13.1.4.1.1.2.8. Offer Information From New Demand Capacity Resources.

(a) All New Demand 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 Demand Capacity

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.

(b) The Project Sponsor for a New Demand Capacity Resource must indicate in the New Demand Capacity Resource Qualification Package if an offer from the New Demand Capacity 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.13.1.4.1.1.3. Initial Analysis for Active Demand Capacity Resources.

For each New Demand Capacity Resource that is an Active Demand Capacity Resource, the ISO shall perform an analysis based on the information provided in the New Demand Capacity 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 Capacity 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 Capacity Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.1.4. Consistency of the New Demand Capacity Resource Qualification Package and New Demand Capacity Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Capacity Resource Qualification Package for consistency with its New Demand Capacity Resource Show of Interest Form. The New Demand Capacity Resource Qualification Package may not contain material changes relative to the New Demand Capacity 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 Capacity 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 Active Demand Capacity 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); or (vi) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.1.1.5. Evaluation of New Demand Capacity Resource Qualification Materials.

The ISO shall review the information submitted by New Demand Capacity 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 Capacity 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 New Demand Capacity 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 Capacity Resources includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule submitted by New Demand Capacity 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 Capacity Resource are satisfied; and
- (e) whether, in the case of a New Demand Capacity Resource that is an On-Peak Demand Resource or Seasonal Peak Demand Resource, 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.13.1.4.1.1.6. Qualification Determination Notification for New Demand Capacity 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 Capacity Resource indicating whether the New Demand Capacity Resource has been accepted for participation in the Forward Capacity Auction.

(a) For a New Demand Capacity Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Capacity Resource type and the Demand Capacity Resource's summer and winter Qualified Capacity, which shall be the ISO-determined summer and winter demand reduction value increased by average avoided peak transmission and distribution losses (that is, eight percent).

(b) For a New Demand Capacity 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.13.1.4.2. Definition of Existing Demand Capacity Resources.

Demand Capacity Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Capacity Resources, shall be Existing Demand Capacity Resources. Existing Demand Capacity Resources shall include and are limited to Demand Capacity 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 this Section III.13.1.4, Existing Demand Capacity 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 Capacity Resources shall be subject to Section III.13.1.2.2.5.2. An On-Peak Demand Resource or Seasonal Peak Demand Resource may not include in its demand reduction value a measure whose Measure Life will expire before the beginning of the associated Capacity Commitment Period.

III.13.1.4.2.1. Qualified Capacity Notification for Existing Demand Capacity Resources.

(a) For each Existing Demand Capacity Resource, the ISO will notify the Resource's Lead Market Participant no later than 20 Business Days before the Existing Capacity Retirement Deadline of: the Demand Capacity Resource type; summer and winter Qualified Capacity (which shall be the summer and winter demand reduction value increased by average avoided peak transmission and distribution losses);

the Load Zone in which the Demand Capacity Resource is located; and, for Active Demand Capacity Resources, the Dispatch Zone in which the resource is located.

(b) If the Lead Market Participant believes that the ISO's assessment of the Qualified Capacity is inaccurate, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification.

(c) If a Market Participant with an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource wishes to change its Demand Capacity Resource type, the Market Participant must submit an Updated Measurement and Verification Plan to reflect the change in its resource type. 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 Capacity Resource type may not be changed during the Capacity Commitment Period.

(d) A Market Participant with an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource may provide an Updated Measurement and Verification Plan as described in Section III.13.1.4.3.1.2 that complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification.

(e) If an Existing Demand Capacity Resource is not submitting a Static De-List Bid, Permanent De-List Bid, or Retirement 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.

III.13.1.4.2.2. Existing Demand Capacity Resource De-List Bids.

An Existing Demand Capacity Resource may submit a Permanent De-List Bid or Retirement De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.5 no later than the Existing Capacity Retirement Deadline or a Static De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.1 no later than the Existing Capacity Qualification Deadline, provided, however, that no de-list bid shall be used as a mechanism to inappropriately qualify Assets associated with Existing Demand Capacity Resources as New Demand Capacity Resources.

III.13.1.4.3. Measurement and Verification Applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

To demonstrate the demand reduction value of an On-Peak Demand Resource or Seasonal Peak Demand Resource, the Project Sponsor or Market Participant of such a resource participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals, or reconfiguration auctions shall submit to the ISO the Measurement and Verification Documents in accordance with this Section III.13.1.4.3 and the ISO New England Manuals. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents.

Measurement and Verification Documents must demonstrate both availability and performance of an On-Peak Demand Resource or Seasonal Peak Demand Resource in reducing demand coincident with Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours such that the reported monthly demand reduction value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manuals and ISO New England Operating Procedures. The Measurement and Verification Documents shall serve as the basis for the claimed demand reduction value of an On-Peak Demand Resource or Seasonal Peak Demand Resource. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved demand reduction value of the On-Peak Demand Resource or Seasonal Peak Demand Resource. The Measurement and Verification Documents shall contain a projection of the On-Peak Demand Resource's or Seasonal Peak Demand Resource's demand reduction value for each month of the Capacity Commitment Period and over the expected Measure Lives associated with the Demand Capacity Resources. An On-Peak Demand Resource's or Seasonal Peak 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. If an On-Peak Demand Resource or Seasonal Peak Demand Resource includes Distributed Generation, the Measurement and Verification Documents must describe the individual metering or metering protocol used to monitor and verify the output of the Distributed Generation, consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals.

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 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 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 Project Sponsor, the Measurement and Verification Documents for an On-Peak Demand Resource or a Seasonal Peak Demand Resource 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 On-Peak Demand Resource or Seasonal Peak Demand Resource 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 Project Sponsor, an Updated Measurement and Verification Plan for an On-Peak Demand Resource or a Seasonal Peak Demand Resource may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Capacity Resource project. The Updated Measurement and Verification Plan may include updated 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 claimed demand reduction value or the Demand Capacity Resource type from the applicable Forward Capacity Auction in which the 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 Capacity Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Project Sponsors for On-Peak Demand Resources and Seasonal Peak Demand Resources shall submit no less frequently than once per year, a statement certifying that the Demand Capacity 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 On-Peak Demand Resources and Seasonal Peak Demand Resources targeting customer facilities with greater than or equal to 10 kW of demand reduction value per facility, 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 On-Peak Demand Resources and Seasonal Peak Demand Resources targeting customer facilities with under 10 kW of demand reduction value per facility, the 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. Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Capacity Resource is permanently delisted 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. 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 or Lead Market Participant to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.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.13.1.4.1.1.6. 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 Capacity Resource, April through November where the summer resource is a Demand Capacity 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 Capacity Resource, December through March where the summer resource is a Demand Capacity 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.13.1.4.1.1.2.7) 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 Capacity 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) [Reserved.]

(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 five 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 Capacity 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 FCM 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 Capacity Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.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 Capacity Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, a Retirement 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, retire 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 and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid and Retirement De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.
- (b) The quantity 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) No later than three Business Days after the Existing Capacity Retirement Deadline, the ISO shall post on its website information concerning Permanent De-List Bids and Retirement De-List Bids.
- (f) The name of each Lead Market Participant submitting Static De-List Bids, Export Bids, and Administrative Export De-List Bids, as well as the number and type of such 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(b), 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, Permanent De-List Bids, and Retirement 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.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Capacity Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Resources) and New Demand Capacity Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the FCM Deposit by the Project Sponsor for a New Generating Capacity Resource or New Demand Capacity 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 Capacity Resource in the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the FCM Deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Capacity Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Capacity Resource clears in the Forward Capacity Auction, financial assurance required prior to the auction pursuant to FAP 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 Capacity Resource clears in the Forward Capacity Auction, the financial assurance required prior to the auction pursuant to FAP will be released 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 Capacity Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Capacity 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 Capacity Resource: (i) fails to provide the required financial assurance as described in the ISO New England Financial Assurance Policy 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 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 Capacity 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 Capacity Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited.

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 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 Section III.13 shall be used to reduce charges 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 or will be delivered over an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff 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 or the Elective Transmission Upgrade 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 Capacity 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, 23 or 25 of Section II of the Transmission, Markets and Services Tariff or where a resource modification does not require a revision to the Interconnection Agreement.

New Generating Capacity Resources \geq 20 MW or an Import Capacity Resource associated with an Elective Transmission Upgrade that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff	New Generating Capacity Resources $<$ 20 MW and \geq 2 MW	Imports and New Demand Capacity Resources (including Distributed Generation)		New Generating Capacity Resources $<$ 2 MW
<i>Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources</i>	<i>Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources</i>			
\$25,000	\$7,500	\$1,000		\$500
<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>	<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>			
\$15,000	\$6,500	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 Capacity 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 Capacity 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.

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 Existing Capacity Retirement Deadline will be in March, approximately four years and three months before the beginning of the Capacity Commitment Period;
- (c) the New Capacity Show of Interest Submission Window will be in April , approximately four years and two months before the beginning of the Capacity Commitment Period;
- (d) the Existing Capacity Qualification Deadline will be in June, approximately four years before the beginning of the Capacity Commitment Period;
- (e) 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
- (f) 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.

Existing Capacity Retirement Deadline	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
March (X-4)	April (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.13.1.4.1.1.2.7) 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.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

- (i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);
- (ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at \$7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

- (iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

- (1) at prices above \$7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;
- (2) at prices below \$7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between \$7.03/kW-month and \$0.00/kW-month and determined by the following quantities:
 - (a) At the price of \$0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.
 - (b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at \$7.03/kW-month, the quantity shall be the lesser of:
 - 1. 35,437 MW; and
 - 2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month;
 - (c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at \$7.03/kW-month, the quantity shall be the lesser of:
 - 1. 35,090 MW; and
 - 2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month;
 - (d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at \$7.03/kW-month, the quantity shall be the lesser of:
 - 1. 34,865 MW; and
 - 2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month

(3) a price of \$7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the amount of capacity for which the Capacity Zone Demand Curve specifies a price of \$0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative \$0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

- (i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an

investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E , respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be p_1, p_2, \dots, p_m , where $P_S > p_1 > p_2 > \dots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be q_1, q_2, \dots, q_m . Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E , shall be taken to be:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \leq p_1, \\ q_2, & \text{if } p_3 < p \leq p_2, \\ \dots & \dots, \\ q_m, & \text{if } p \leq p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic Delist Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five

prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be bid into the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be

included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to

Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources.** Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Capacity Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same

manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 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 a Dynamic De-List 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. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, 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.

(e) **Repowering.** Offers and bids associated with a resource participating 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) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics.** Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

- (1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);
- (2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);
- (3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:
 - (i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits), or;
 - (ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;
- (4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:
 - (i) that interface's approved capacity transfer limit (net of tie benefits), or;
 - (ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

- (1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;
- (2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then the auctioneer shall publish the quantity of capacity in the Capacity Zone from Demand Capacity Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone.**

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price, and also shall publish the quantity of capacity from Demand Capacity Resources by type at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones.** For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

- (1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero, and;
- (2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the export-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-

constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and the quantity of capacity in the Capacity Zone from Demand Capacity Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-

TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is \$11.35/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is \$8.04/kW-month.

CONE and Net CONE shall be recalculated using updated data coincident with the recalculation of Offer Review Trigger Prices pursuant to Section III.A.21.1.2. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e). Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by \$0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the bid has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated if either of the following conditions is met in the initial auction clearing process: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation); or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation) and the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price. The second run of the auction-clearing process: (i) excludes all Proxy De-List Bid(s), (ii) includes the offers and bids of resources that did not receive a Capacity Supply Obligation in the first run of the auction-clearing process, and (iii) includes the capacity of resources, or portion thereof, that received a Capacity Supply Obligation in the first run of the auction-clearing process. The second run of the auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receive a Capacity Supply Obligation as a result of the first run of the auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity

Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Economic Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. Reliability Review.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid to determine whether the capacity associated with that de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station.. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. De-list bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) Where a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction.

(c) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject the de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability. Resources that submitted

Permanent De-List Bids or Retirement De-List Bids shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii)).

(g) If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1.

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List

Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the “just and reasonable” standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource’s Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the

Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability.** If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Capacity Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO:** A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the

Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission:** In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the Capacity Commitment Period for which the Retirement De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: submitted a Retirement De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III.13.1.2.3.1.5(d); elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction; or, for a resource, or portion thereof, that submitted a Permanent De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless 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. The interconnection rights, or relevant portion thereof, for the resource will

terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the Capacity Commitment Period for which its Permanent De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: submitted a Permanent De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III.13.1.2.3.1.5(d); was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) 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.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity

Clearing Price for each import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. Capacity Clearing Price Floor.

In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below \$3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches \$3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

- (i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to \$3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.
- (ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).
- (iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).
- (iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource's payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.
- (v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply 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 Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7.

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity,

then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

- (a) [Reserved.]
- (b) If multiple projects may be rationed, they will be rationed proportionately.
- (c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.
- (d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources) shall be cleared.

III.13.3. Critical Path Schedule Monitoring.

III.13.3.1. Resources Subject to Critical Path Schedule Monitoring.

III.13.3.1.1. New Resources Electing Critical Path Schedule Monitoring.

A Project Sponsor that submits a critical path schedule for a New Capacity Resource in the qualification process may request that the ISO monitor that resource's compliance with its critical path schedule in accordance with the provisions of this Section III.13.3. The ISO will monitor the New Capacity Resource's compliance from the time the ISO approves the request until the resource achieves Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4(c), or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

In addition, a Lead Market Participant with a New Import Capacity Resource backed by one or more existing External Resources seeking to qualify for Capacity Commitment Period(s) prior to the Capacity Commitment Period associated with the Forward Capacity Auction for which it is qualifying must request monitoring under this Section III.13.3.1.1.

A request under this Section III.13.3.1.1 must be made in writing no later than five Business Days after the deadline for submission of the FCM Deposit pursuant to Section III.13.1.9.1.

III.13.3.1.2. New Resources Clearing in the Forward Capacity Auction.

For each new resource required to submit a critical path schedule in the qualification process, including but not limited to a New Generating Capacity Resource (pursuant to Section III.13.1.1.2.2), a New Import Capacity Resource backed by a new External Resource (pursuant to Section III.13.1.3.5), or a New Demand Capacity Resource (pursuant to Section III.13.1.4), if capacity from that resource clears in the Forward Capacity Auction, then the ISO shall monitor that resource's compliance with its critical path schedule in accordance with the provisions of this Section III.13.3 (regardless of whether the Project Sponsor requested monitoring pursuant to Section III.13.3.1.1) from the time that the Forward Capacity Auction is conducted until the resource achieves Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4(c), or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

III.13.3.1.3. New Resources Not Offering or Not Clearing in the Forward Capacity Auction.

If no capacity from a new resource that was required to submit a critical path schedule in the qualification process clears in the Forward Capacity Auction, or if such a resource does not submit an offer in the Forward Capacity Auction, then the ISO shall not monitor that resource's compliance with its critical path schedule after the Forward Capacity Auction unless the Project Sponsor previously requested pursuant to Section III.13.3.1.1 that the ISO continue to monitor that resource's compliance with its critical path schedule. However, if a New Generating Capacity Resource participated but did not clear in the Forward Capacity Auction either as: (i) a Conditional Qualified New Resource, or (ii) a New Generating Capacity Resource with a higher priority in the queue and overlapping interconnection impacts with a Conditional Qualified New Resource, the ISO will not continue to monitor that resource's compliance with its critical path schedule even if that resource requested critical path schedule monitoring pursuant to Section III.13.3.1.1.

III.13.3.2. Quarterly Critical Path Schedule Reports.

For each new resource that is being monitored for compliance with its critical path schedule, the Project Sponsor for that resource must provide a written critical path schedule report to the ISO no later than five Business Days after the end of each calendar quarter. If the Project Sponsor does not provide a written critical path schedule report to the ISO by the fifth Business Day after the end of the calendar quarter, then the ISO shall issue a notice thereof to the Project Sponsor. If the Project Sponsor fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.13.3.4(c). Each critical path schedule report shall include the following:

III.13.3.2.1. Updated Critical Path Schedule.

The critical path schedule report must include a complete updated version of the critical path schedule as described in Section III.13.1.1.2.2.2, dated contemporaneously with the submission of the critical path schedule report. The updated critical path schedule should clearly indicate if the Project Sponsor is proposing to change any of the milestones or dates from the previously submitted version of the critical path schedule, and must include an explanation of any such proposed changes. In the critical path schedule report, the Project Sponsor should also explain in detail any proposed changes to the project design and the potential impact of such changes on the amount of capacity the resource will be able to provide.

III.13.3.2.2. Documentation of Milestones Achieved.

(a) For all new resources except for Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW (discussed in Section III.13.3.2.2(b)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Major Permits.** For each major permit described in the critical path schedule, the Project Sponsor shall provide documentation showing that the permit was applied for and obtained as described in the critical path schedule. For permit applications, this documentation could include a dated copy of the permit application or cover letter requesting the permit. For approved permits, this documentation could include a dated copy of the approved permit or letter granting the permit from the permitting authority.

(ii) **Project Financing Closing.** The Project Sponsor shall provide documentation showing that the sources of financing identified in the critical path schedule have committed to provide the amount of financing described in the critical path schedule. This documentation could include copies of commitment letters from the sources of financing.

(iii) **Major Equipment Orders.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was ordered as described in the critical path schedule. This documentation should include a copy of a dated confirmation of the order from the manufacturer or supplier. This documentation should confirm scheduled delivery dates consistent with milestone Section III.13.3.2.2(a)(vi).

(iv) **Substantial Site Construction.** The Project Sponsor shall provide documentation showing that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs.

(v) **Major Equipment Delivery.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was delivered to the project site and received as preliminarily acceptable as described in the critical

path schedule. This documentation should include a copy of a dated confirmation of delivery to the project site.

(vi) **Major Equipment Testing.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the component was tested, including major systems testing as appropriate for the specific technology as described in the critical path schedule, and that the test results demonstrate the equipment's suitability to allow, in conjunction with other major component, subsequent Commercial Operation of the project in accordance with the amount of capacity obligated from the resource in the Capacity Commitment Period in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning.** The Project Sponsor shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity obligated from the resource in the Capacity Commitment Period. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Project Sponsor is not required to provide documentation of Commercial Operation to the ISO as part of the ISO's critical path schedule monitoring. The ISO shall confirm that the resource has achieved Commercial Operation as described in the critical path schedule through the resource's compliance with the other relevant requirements of the Transmission, Markets and Services Tariff and the ISO New England System Rules.

(ix) **Transmission Upgrades.** If during the qualification process it was determined that, because of overlapping interconnection impacts, transmission upgrades are needed for the new resource to complete its interconnection, then the Project Sponsor shall provide documentation showing that the transmission upgrades have been completed.

(b) For Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion.** The Project Sponsor shall provide documentation showing the total offered demand reduction value achieved as of target dates which are: (a) the cumulative percentage of total demand reduction value achieved on target date 1 occurring five weeks prior to the first Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; (b) the cumulative percentage of total demand reduction value achieved on target date 2 occurring five weeks prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; and (c) target date 3 which is the date the resource is expected to achieve commercial operation, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100 percent of the total demand reduction value must be complete.

(ii) **Pipeline Analysis.** If the Project Sponsor proposes in its New Demand Capacity Resource Qualification Package a cumulative percentage of demand reduction value achieved that is 30 percent or less by the second critical path schedule target date, then the Project Sponsor shall provide a pipeline analysis to the ISO as specified in Section III.13.1.4.1.1.2.6 of Market Rule 1.

(iii) **Additional Requirements.** For each customer and each prospective customer the Project Sponsor shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Asset has been registered with the ISO, then the Project Sponsor shall also provide the Asset identification number.

III.13.3.2.3. Additional Relevant Information.

The Project Sponsor must include in the critical path schedule report any other information regarding the status or progress of the project or any of the project milestones that might be relevant to the ISO's evaluation of the feasibility of the project being built in accordance with the critical path schedule or the feasibility that the project will meet the requirement that the project achieve Commercial Operation no later than the start of the relevant Capacity Commitment Period.

III.13.3.2.4. Additional Information for Resources Previously Counted As Capacity.

For each resource participating 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 or New Demand Capacity Resource

pursuant to Section III.13.1.4.1 and clearing in that auction, the Project Sponsor must provide information in the critical path schedule report demonstrating: (a) the shedding of the resource's Capacity Supply Obligation in accordance with the provisions of Section III.13.1.1.2.2.5(c); and (b) that the relevant cost threshold (described in Sections III.13.1.1.1.2, III.13.1.1.1.3, and III.13.1.1.1.4) is being met.

III.13.3.3. Failure to Meet Critical Path Schedule.

If the ISO determines that any critical path schedule milestone date has been missed, or if the Project Sponsor proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.13.3.2.1), then the ISO shall consult with the Project Sponsor to determine the impact of the missed milestone or proposed revision, and shall determine a revised date for the milestone and for any other milestones affected by the change including Commercial Operation of the project. If a milestone date is revised for any reason, the ISO may require the Project Sponsor to submit a written report to the ISO on the fifth Business Day of each month until the revised milestone is achieved detailing the progress toward meeting the revised milestone. If the Project Sponsor does not provide a written critical path schedule report to the ISO on the fifth Business Day of a month, then the ISO shall issue a notice thereof to the Project Sponsor. If the Project Sponsor fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.13.3.4(c). Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.13.3.2.

III.13.3.4. Covering Capacity Supply Obligation where Resource will Not Achieve Commercial Operation by the Start of the Capacity Commitment Period.

Except as described in Section III.13.3.7, if as a result of milestone date revisions, the Commercial Operation milestone date is after the start of any Capacity Commitment Period in which the resource has a Capacity Supply Obligation (except for a New Generating Capacity Resource that has cleared in the Forward Capacity Auction and 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), then the Project Sponsor must take actions to cover the entire Capacity Supply Obligation for the portion of the Capacity Commitment Period for which the project will not have achieved Commercial Operation, as follows:

(a) The Project Sponsor may cover its Capacity Supply Obligation through reconfiguration auctions as described in Section III.13.4 or one or more Capacity Supply Obligation Bilaterals, subject to the satisfaction of the requirements in Section III.13.5.

(b) If, by the time demand bids are due for the third annual reconfiguration auction for the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, the Project Sponsor has not covered its full Capacity Supply Obligation for the portion of the Capacity Commitment Period for which the project will not have achieved Commercial Operation, then the ISO shall submit a demand bid in that annual reconfiguration auction on the Project Sponsor's behalf for a quantity equal to the largest monthly Capacity Supply Obligation for the Capacity Commitment Period that has not been covered, at the Forward Capacity Auction Starting Price (or, for any demand bid submitted by the ISO in the third annual reconfiguration auction associated with the seventh Capacity Commitment Period, at \$12.11/kW-month), with all payments, charges, rights, obligations, and other results associated with such demand bid applying to the Project Sponsor as if the Project Sponsor itself had submitted the demand bid.

(c) If the Project Sponsor fails to comply with the requirements of Sections III.13.3.2 or III.13.3.3, or if the Capacity Supply Obligation is not covered as described in Sections III.13.3.4(a) and III.13.3.4(b), or if the Project Sponsor covers the Capacity Supply Obligation for two Capacity Commitment Periods, then the ISO, after consultation with the Project Sponsor, shall have the right, through a filing with the Commission, to terminate the resource's Capacity Supply Obligation for any future Capacity Commitment Periods and the resource's right to any payments associated with that Capacity Supply Obligation in the Capacity Commitment Period, and to adjust the resource's qualified capacity for participation in the Forward Capacity Market; provided that, where a Project Sponsor voluntarily withdraws its resource from critical path schedule monitoring in accordance with Section III.13.3.6, no filing with the Commission shall be necessary to terminate the resource's Capacity Supply Obligation. Upon Commission ruling, the Project Sponsor shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation. If in these circumstances, however, the ISO does not take steps to terminate the resource's Capacity Supply Obligation and instead permits the Project Sponsor to continue to cover its Capacity Supply Obligation, such continuation shall be subject to the ISO's right to revoke that permission and to file with the Commission to terminate the resource's Capacity Supply Obligation, and subject to continued reporting by the Project Sponsor as described in this Section III.13.3.

III.13.3.5. Termination of Interconnection Agreement.

If the ISO terminates, or files with the Commission to terminate, a resource's Capacity Supply Obligation as described in Section III.13.3.4(c), the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. If the

Project Sponsor continues to cover all of its Capacity Supply Obligations while challenging such termination before the Commission, it shall retain its Queue Position.

III.13.3.6. Withdrawal from Critical Path Schedule Monitoring.

A Project Sponsor may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO. The ISO also may deem a resource withdrawn from critical path schedule monitoring if the Project Sponsor does not adhere to the requirements of this Section III.13.3. Any resource withdrawn from critical path schedule monitoring shall be subject to the provisions of Section III.13.3.4.

III.13.3.7 Request to Defer Capacity Supply Obligation

A resource that has not yet achieved Commercial Operation and that is subject to critical path schedule monitoring by the ISO pursuant to this Section III.13.3 may seek to defer the applicability of its entire Capacity Supply Obligation by one year pursuant to the provisions of this Section III.13.3.7.

A Project Sponsor seeking such a deferral must notify the ISO in writing no later than the first Business Day in September of the year prior to the third annual reconfiguration auction for the Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If, after consultation with the Project Sponsor, the ISO determines that the absence of the capacity in the first Capacity Commitment Period in which the resource has a Capacity Supply Obligation, as well as in the subsequent Capacity Commitment Period, would result in the violation of any NERC or NPCC (or their successors) criteria or of the ISO New England System Rules, not solely that it may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for the Capacity Zone, then the ISO will review the specific reliability need with and seek feedback from the Reliability Committee and provide the Project Sponsor with a written determination to that effect within 30 days of the Project Sponsor's notification to the ISO.

If the ISO provides such a written determination, then the Project Sponsor may file with the Commission, no later than the first Business Day in November of the year prior to the third annual reconfiguration auction, a request to defer the applicability of its Capacity Supply Obligation by one year. Any such filing must include the ISO's written determination, and must also demonstrate that the deferral is critical to the resource's ability to achieve Commercial Operation and that the reasons for the deferral are beyond the control of the Project Sponsor.

If the Commission approves the request, all of the rights, obligations, payments, and charges associated with the Capacity Supply Obligation described in Section III.13.6 and Section III.13.7 shall only apply beginning one year after the start of the Capacity Commitment Period in which the resource has a Capacity Supply Obligation. Notwithstanding any other provision of this Section III.13, if the resource achieves commercial operation prior to the deferred date, it will not be eligible to receive revenue in the Forward Capacity Market until the deferred date. Beginning on the deferred date, all of the rights, obligations, payments, and charges associated with the Capacity Supply Obligation shall apply, and 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) associated with the Forward Capacity Auction in which the resource cleared as a new resource shall apply for the full duration of the Capacity Supply Obligation (including multi-year elections made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7). Neither the Project Sponsor, nor the ISO on the Project Sponsor's behalf, will take actions to cover the resource's Capacity Supply Obligation for the deferral period as described in Section III.13.3.4, but the other requirements of III.13.3, including all reporting requirements and the ISO's right to seek termination, shall continue to apply during the deferral period. Upon Commission approval of the deferral, the resource may not participate in any reconfiguration auctions or Capacity Supply Obligation Bilaterals for any portion of the deferral period. Beginning at 8:00 a.m. (Eastern Time) 30 days after Commission approval of the request, the Project Sponsor shall be required to provide an additional amount of financial assurance as described in Section VII.B.2.c of the ISO New England Financial Assurance Policy.

Notwithstanding any other provision of this Section III.13, if any of the resource's Capacity Supply Obligation in the deferral period was shed in a reconfiguration auction or Capacity Supply Obligation Bilateral prior to Commission approval of the deferral request, then the resource's settlements shall be adjusted by the ISO to ensure that the resource does not receive any payments associated with that transaction in excess of the charges associated with that transaction; the resource will be responsible for any charges in excess of payments.

III.13.4. Reconfiguration Auctions.

For each Capacity Commitment Period, the ISO shall conduct annual and monthly reconfiguration auctions as described in this Section III.13.4. Reconfiguration auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in reconfiguration auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Sections III.13.4.5 and III.13.4.7) to clear supply offers (i.e., offers to assume a Capacity Supply Obligation) and demand bids (i.e., bids to shed a Capacity Supply Obligation) for each Capacity Zone included in the reconfiguration auction. Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected. Resources that are able to meet the requirements in other Capacity Zones shall be allowed to clear to meet such requirements, subject to the constraints modeled in the auction.

III.13.4.1. Capacity Zones Included in Reconfiguration Auctions.

Each reconfiguration auction associated with a Capacity Commitment Period shall include each of, and only, the final Capacity Zones and external interfaces as determined through the Forward Capacity Auction for that Capacity Commitment Period, as described in Section III.13.2.3.4.

III.13.4.2. Participation in Reconfiguration Auctions.

Each supply offer and demand bid in a reconfiguration auction must be associated with a specific resource, and must satisfy the requirements of this Section III.13.4.2. All resource types may submit supply offers and demand bids in reconfiguration auctions. In accordance with Section III.A.9.2 of *Appendix A* of this Market Rule 1, supply offers and demand bids submitted for reconfiguration auctions shall not be subject to mitigation by the Internal Market Monitor. A supply offer or demand bid submitted for a reconfiguration auction shall not be limited by the associated resource's Economic Minimum Limit. Offers composed of separate resources may not participate in reconfiguration auctions. Participation in any reconfiguration auction is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of the offer and bid deadline. For annual reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 30 days prior to that deadline. No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 10 Business Days prior to that deadline. Upon issuance of the monthly bilateral results for the associated

obligation month, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that monthly auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions in which the most recently approved Winter Seasonal Claimed Capability established as of the fifth Business Day in June of the relevant Capacity Commitment Period is greater than the Winter ARA Qualified Capacity for the third annual reconfiguration auction, the ISO shall apply the greater of these two values to offer limits starting with the first monthly reconfiguration auction in the winter delivery period for the relevant Capacity Commitment Period, limited, as applicable, by the resource's CNR Capability.

III.13.4.2.1. Supply Offers.

Submission of supply offers in reconfiguration auctions shall be governed by this Section III.13.4.2.1. All supply offers in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, in dollars per kW/month. In no case may capacity associated with a Retirement De-List Bid or a Permanent De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that, or any subsequent, Capacity Commitment Period, or any portion thereof. In no case may capacity associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof.

III.13.4.2.1.1. Amount of Capacity That May Be Submitted in a Supply Offer in an Annual Reconfiguration Auction.

For each month of the Capacity Commitment Period associated with the annual reconfiguration auction, the ISO shall calculate the difference between the Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, and the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for the month. The minimum of these 12 values shall be the amount of capacity up to which a resource may submit a supply offer in the annual reconfiguration auction.

III.13.4.2.1.2. Calculation of Summer ARA Qualified Capacity and Winter ARA Qualified Capacity.

III.13.4.2.1.2.1. First Annual Reconfiguration Auction and Second Annual Reconfiguration Auction.

III.13.4.2.1.2.1.1. Generating Capacity Resources Other than Intermittent Power Resources.

III.13.4.2.1.2.1.1.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the higher of the resource's summer Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any summer Seasonal Claimed Capability values for summer periods completed after the Existing Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and where the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.1.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the higher of the resource's winter Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any winter Seasonal Claimed Capability values for winter periods completed after the Existing

Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and where the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2. Intermittent Power Resources.

III.13.4.2.1.2.1.2.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined summer Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined winter Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.3. Import Capacity Resources Backed By an External Control Area.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to its summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period.

III.13.4.2.1.2.1.3.1. Import Capacity Resources Backed by One or More External Resources.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be the greater of:

(a) the summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period; and

(b) the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October and, if submitted for a New Import Capacity Resource backed by one or more External Resources, also subject to the satisfaction of the requirements

in Sections III.13.1.3.5.1(b), III.13.1.3.5.2, and III.13.3.1.1 and the relevant financial assurance requirements as described in Section III.13.1.9 and the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.4. Demand Capacity Resources.

III.13.4.2.1.2.1.4.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined summer Qualified Capacity.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.4.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined winter Qualified Capacity.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2. Third Annual Reconfiguration Auction.

III.13.4.2.1.2.2.1. Generating Capacity Resources other than Intermittent Power Resources.

III.13.4.2.1.2.2.1.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's summer Seasonal Claimed Capability value in effect after the most recently completed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.1.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2. Intermittent Power Resources.

III.13.4.2.1.2.2.2.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the lesser of its most recently-determined summer Qualified Capacity and its summer Seasonal Claimed Capability value in effect after the most recently competed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the lesser of its most recently-determined winter Qualified Capacity and its winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.3. Import Capacity Resources.

III.13.4.2.1.2.2.3.1 Import Capacity Resources Backed by an External Control Area.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its summer Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October. For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its winter Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October.

III.13.4.2.1.2.2.3.2. Import Capacity Resources Backed by One or More External Resources.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be the lesser of:

(a) the summer Qualified Capacity and winter Qualified Capacity, respectively, as determined by the most recent Forward Capacity Auction that does not reflect a change to the Import Capacity Resource applicable to that Capacity Commitment Period; and

(b) the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October and, if submitted for a New Import Capacity Resource backed by one or more External Resources, also subject to the satisfaction of the requirements in Sections III.13.1.3.5.1(b), III.13.1.3.5.2, and III.13.3.1.1 and the relevant financial assurance requirements as described in Section III.13.1.9 and the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.4. Demand Capacity Resources.

III.13.4.2.1.2.2.4.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the lesser of: (i) its most recently-determined summer Qualified Capacity and (ii) its summer Seasonal DR Audit value or summer Passive DR Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.4.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the lesser of: (i) its most recently-determined winter Qualified Capacity and (ii) its winter Seasonal DR Audit value or winter Passive DR Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.3. Adjustment for Significant Decreases in Capacity.

For each month of the Capacity Commitment Period associated with the third annual reconfiguration auction, for each resource that has achieved Commercial Operation, the ISO shall subtract the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, from the amount of capacity from the resource that is subject to a Capacity Supply Obligation for the month. For the month associated with the greatest of these 12 values, if the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity (as applicable) is below the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month by more than the lesser of 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or 40 MW, then the following provisions shall apply:

(a) The Lead Market Participant may submit a written plan to the ISO with any necessary supporting documentation describing the measures that will be taken and demonstrating that the resource will be able to provide an amount of capacity consistent with its total Capacity Supply Obligation for the Capacity Commitment Period by the start of all months in that Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If submitted, such a plan must be received by the ISO no later than 10 Business Days after the ISO has notified the Lead Market Participant of its Summer ARA Qualified Capacity and Winter ARA Qualified Capacity for the third annual reconfiguration auction.

(b) If no such plan as described in Section III.13.4.2.1.3(a) is timely submitted to the ISO, or if such a plan is timely submitted but the ISO determines that the plan does not demonstrate that the resource will be able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, then the ISO shall enter a demand bid at the Forward Capacity Auction Starting Price (or, in the case of a resource that cleared in

the seventh Forward Capacity Auction, at \$12.11/kW-month) on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) in the third annual reconfiguration auction in an amount equal to the greatest of the 12 monthly values determined pursuant to this Section III.13.4.2.1.3.

(c) If the ISO determines that the resource is not able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, and if the resource was part of an offer composed of separate resources when it qualified to participate in the relevant Forward Capacity Auction, then before a demand bid is entered for the resource pursuant to subsection (b) above, the resource may submit monthly Capacity Supply Obligation Bilaterals, subject to the satisfaction of the requirements in Section III.13.5, to cover the deficiency for the months of the Capacity Commitment Period in which the Capacity Supply Obligation is associated with participation in an offer composed of separate resource prior to the third annual reconfiguration auction, but in no case may such a Capacity Supply Obligation Bilateral for a month be for an amount of capacity greater than the difference between the resource's Capacity Supply Obligation for the month and the resource's lowest monthly Capacity Supply Obligation during the Capacity Commitment Period.

III.13.4.2.1.4. Amount of Capacity That May Be Submitted in a Supply Offer in a Monthly Reconfiguration Auction.

A resource that has not achieved Commercial Operation by the offer and bid deadline for a monthly reconfiguration auction may not submit a supply offer for that reconfiguration auction, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a supply offer for that reconfiguration auction in an amount up to the absolute value of its Capacity Supply Obligation. The amount of capacity up to which a resource may submit a supply offer in a monthly reconfiguration auction shall be the difference (but in no case less than zero) between (i) the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity as adjusted pursuant to Section III.13.4.2, as applicable, for the auction month for the third annual reconfiguration auction for the relevant Capacity Commitment Period; and (ii) the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month. However, a resource may not submit a supply offer for a monthly reconfiguration auction if it is on an approved outage during that month.

III.13.4.2.1.5. ISO Review of Supply Offers.

Supply offers in reconfiguration auctions 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 reviews will consider the location and operating and rating limitations of resources associated with cleared supply offers to ensure reliability standards will remain satisfied if the offer is accepted. The ISO shall reject supply offers that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction. The ISO's reliability reviews will assess such offers, beginning with the marginal resource, 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. Supply offers that cannot meet the applicable reliability needs will be rejected in their entirety and the resource will not be rejected in part. Rejected resources will not be further included in clearing the reconfiguration auction and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.2.2. Demand Bids in Reconfiguration Auctions.

Submission of demand bids in reconfiguration auctions shall be governed by this Section III.13.4.2.2. All demand bids in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the amount of capacity bid in MW, and the price, in dollars per kW/month.

- (a) To submit a demand bid in a reconfiguration auction, a resource must have a Capacity Supply Obligation for the Capacity Commitment Period (or portion thereof, as applicable) associated with that reconfiguration auction. Where capacity associated with a Self-Supplied FCA Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period is offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof, a resource acquiring a Capacity Supply Obligation shall not as a result become a Self-Supplied FCA Resource.
- (b) Each demand bid submitted to the ISO for reconfiguration auction shall be no greater than the amount of the resource's capacity that is already obligated for the Capacity Commitment Period (or portion thereof, as applicable) as of the offer and bid deadline for the reconfiguration auction.
- (c) All demand bids in reconfiguration auctions 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 reviews will consider the location and operating and rating limitations of resources associated with cleared demand bids to ensure reliability standards will remain satisfied if the committed

capacity is withdrawn. The ISO shall reject demand bids that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction, provided that for annual reconfiguration auctions associated with a Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall not reject a demand bid solely on the basis that acceptance of the demand bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs). For monthly reconfiguration auctions, the ISO shall obtain and consider information from the Local Control Center regarding whether the capacity associated with demand bids that would otherwise clear from resources with a Capacity Supply Obligation is needed for local system conditions. The ISO's reliability reviews will assess such bids, beginning with the marginal resource, 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. Where the applicable reliability needs cannot be met if a Demand Bid is cleared, such Demand Bids will be rejected in their entirety and the resource will not be rejected in part. Demand Bids from rejected resources will not be further included in clearing the reconfiguration auction, and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.3. ISO Participation in Reconfiguration Auctions.

The ISO shall not submit supply offers or demand bids in monthly reconfiguration auctions. The ISO shall submit supply offers and demand bids in annual reconfiguration auctions as appropriate to address year-to-year changes in the Installed Capacity Requirement (net of HQICCs), Local Sourcing Requirements and Maximum Capacity Limits for the associated Capacity Commitment Period, to procure capacity not purchased in the Forward Capacity Auction as a result of the "Inadequate Supply" rule for Forward Capacity Auctions conducted prior to June 2015, to procure any shortfall in capacity resulting from a resource's achieving Commercial Operation at a level less than that resource's Capacity Supply Obligation or other significant decreases in capacity, and to address any changes in external interface limits, as follows:

- (a) For each Capacity Commitment Period that begins on or before June 1, 2017, the ISO shall submit supply offers and demand bids in annual reconfiguration auctions as appropriate to ensure that the applicable Installed Capacity Requirement (net of HQICCs), Local Sourcing Requirements, Maximum Capacity Limits, and external interface limits are respected. Where less capacity than needed is obligated, the ISO shall submit demand bids as appropriate to procure the additional needed capacity in each

subsequent annual reconfiguration auction until the need is met. Where more capacity than needed is obligated, the ISO may in its discretion submit supply offers in subsequent annual reconfiguration auctions to release the excess capacity, but in any case the ISO shall be required to submit supply offers as appropriate in the third annual reconfiguration auction for a Capacity Commitment Period to release the excess capacity.

(b) For each Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall submit demand bids for the amount of additional capacity needed to meet the Local Sourcing Requirements and shall submit supply offers in the third annual reconfiguration auction for a Capacity Commitment Period to release capacity exceeding the Maximum Capacity Limits or external interface limits.

(c) No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall provide notice regarding whether the ISO will be submitting supply offers or demand bids in that auction.

(d) Any demand bid submitted by the ISO in an annual reconfiguration auction shall be at the Forward Capacity Auction Starting Price, except for any demand bids submitted by the ISO in annual reconfiguration auctions associated with the seventh Capacity Commitment Period, which shall be at \$12.11/kW-month.

(e) Any supply offer submitted by the ISO in an annual reconfiguration auction shall be in the form of a supply curve having the following characteristics:

(i) at prices equal to or greater than 0.75 times the Capacity Clearing Price, as adjusted pursuant to Section III.13.2.7.3(b), from the Forward Capacity Auction for the Capacity Commitment Period covered by the annual reconfiguration auction, the ISO shall offer the full amount of the surplus;

(ii) at prices between 0.75 times such Capacity Clearing Price and 0.25 times such Capacity Clearing Price, the amount of the surplus offered by the ISO shall decrease linearly (for example, at 0.5 times such Capacity Clearing Price, the ISO shall offer half of the amount of the surplus); and

(iii) At prices equal to or below 0.25 times such Capacity Clearing Price, the ISO shall offer no capacity.

(f) For purposes of this Section III.13.4.3, the Forward Capacity Auction Starting Price shall be the Forward Capacity Auction Starting Price associated with the Forward Capacity Auction for the same Capacity Commitment Period addressed by the reconfiguration auction, as determined pursuant to Section III.13.2.4.

(g) Supply offers and demand bids submitted by the ISO in annual reconfiguration auctions are not subject to the requirements and limitations described in Section III.13.4.2.

(h) Supply offers and demand bids submitted by the ISO in annual reconfiguration auctions are not associated with a resource.

III.13.4.4. Clearing Offers and Bids in Reconfiguration Auctions.

All supply offers and demand bids may be cleared in whole or in part in all reconfiguration auctions. If after clearing, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.4.5. Annual Reconfiguration Auctions.

Except as provided below, after the Forward Capacity Auction for a Capacity Commitment Period, and before the start of that Capacity Commitment Period, the ISO shall conduct three annual reconfiguration auctions for capacity commitments covering the whole of that Capacity Commitment Period. For each annual reconfiguration auction, the capacity demand curves, New England Control Area and Capacity Zone capacity requirements and external interface limits, as updated pursuant to Section III.12, shall be modeled in the auction consistent with the Forward Capacity Auction for the associated Capacity Commitment Period. For purposes of the annual reconfiguration auctions, the Forward Capacity Auction Starting Price used to define the System-Wide Capacity Demand Curve shall be the Forward Capacity Auction Starting Price associated with the Forward Capacity Auction for the same Capacity Commitment Period addressed by the reconfiguration auction.

III.13.4.5.1. Timing of Annual Reconfiguration Auctions.

Except for the first five Capacity Commitment Periods, the first annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of June that is approximately 24 months before

the start of the Capacity Commitment Period. The second annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of August that is approximately 10 months before the start of the Capacity Commitment Period. The third annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of March that is approximately 3 months before the start of the Capacity Commitment Period. There shall be no first annual reconfiguration auction for the first five Capacity Commitment Periods. The table below illustrates the annual reconfiguration auction timing provisions stated above, providing the schedule of annual reconfiguration auctions for the first eight Capacity Commitment Periods.

First Annual Reconfiguration Auction	Second Annual Reconfiguration	Third Annual Reconfiguration	Capacity Commitment Period Begins
N/A	May 2009	March 2010	June 1, 2010
N/A	May 2010	March 2011	June 1, 2011
N/A	May 2011	March 2012	June 1, 2012
N/A	May 2012	March 2013	June 1, 2013
N/A	August 2013	March 2014	June 1, 2014
June 2013	August 2014	March 2015	June 1, 2015
June 2014	August 2015	March 2016	June 1, 2016
June 2015	August 2016	March 2017	June 1, 2017

III.13.4.5.2. Acceleration of Annual Reconfiguration Auction.

If the difference between the forecasted Installed Capacity Requirement (net of HQICCs) for a Capacity Commitment Period and the amount of capacity obligated for that Capacity Commitment Period is sufficiently large, then the ISO may, upon reasonable notice to Market Participants, conduct an annual reconfiguration auction as much as six months earlier than its normally-scheduled time.

III.13.4.6. [Reserved.]

III.13.4.7. Monthly Reconfiguration Auctions.

Prior to each month in the Capacity Commitment Period, the ISO shall conduct a monthly reconfiguration auction for whole-month capacity commitments during that month. For each monthly reconfiguration auction, the Local Sourcing Requirement and Maximum Capacity Limit applicable for each Capacity Zone and external interface limits, as updated pursuant to Section III.12, shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in monthly reconfiguration auctions.

III.13.4.8. Adjustment to Capacity Supply Obligations.

For each supply offer that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be increased by the amount of capacity that clears. For each demand bid that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be decreased by the amount of capacity that clears.

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 Capacity Performance Bilaterals in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.

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. A seasonal Capacity Supply Obligation Bilateral can be entered into only during the Capacity Supply Obligation Bilateral window associated with the third Annual Reconfiguration Auction, must be contained within a single Capacity Commitment Period, and must contain all the months in the summer or winter season identified by the Capacity Transferring Resource and only those months. For the purposes of this Section III.13.5, the summer season of a Demand Capacity Resource is all of the months from June through November and April through May of the same Capacity Commitment Period and the winter season of a Demand Capacity Resource is all of the months from December through March; for all other resource types, the summer season is all of the months from June through September and the winter season is all of the months October through May. Prior to January 1, 2017, a seasonal Capacity Supply Obligation Bilateral can only be entered into if the Capacity Transferring Resource has been identified by the ISO as a resource having a significant decrease pursuant to Section III.13.4.2.1.3.

(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 month, season or Capacity Commitment 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 month, season or Capacity Commitment 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. If the season of the Capacity Transferring Resource is not aligned with the season of the Capacity Acquiring Resource and the seasonal Capacity Supply Obligation Bilateral spans more than one season of the Capacity Acquiring Resource, the lowest monthly amount of unobligated Qualified Capacity of the Capacity Acquiring Resource will be used.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource's unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.

(d) [Reserved.]

(e) [Reserved.]

(f) [Reserved.]

(g) [Reserved.]

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant 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 and Prior Notification to the ISO.

The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

A Lead Market Participant or Project Sponsor seeking to submit a monthly Capacity Supply Obligation Bilateral pursuant to Section III.13.3.4 (covering where resource will not achieve commercial operation by start of Capacity Commitment Period) or a monthly Capacity Supply Obligation bilateral pursuant to Section III.13.4.2.1.3(c) (significant decrease of offers composed of separate resources) must notify the ISO in writing of its intention to do so no later than four Business Days prior to the start of the relevant annual Capacity Supply Obligation Bilateral submittal window.

Prior to January 1, 2017, a Lead Market Participant or Project Sponsor seeking to submit a seasonal Capacity Supply Obligation Bilateral must notify the ISO of its intention to do so no later than four Business Days prior to the start of the Capacity Supply Obligation Bilateral window associated with the third annual reconfiguration auction.

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 and seasonal 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 and seasonal 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 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. Capacity Performance Bilaterals.

A resource's Capacity Performance Score during a Capacity Scarcity Condition may be adjusted by entering into a Capacity Performance Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. Eligibility.

If a resource has a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five-minute interval so long as both resources were subject to the same Capacity Scarcity Condition.

III.13.5.3.2. Submission of Capacity Performance Bilaterals.

The Lead Market Participant for a resource having a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition may submit a Capacity Performance Bilateral to the ISO assigning all or a portion of its Capacity Performance Score for that interval to another resource, subject to the eligibility requirements specified in Section III.13.5.3.1. The Capacity Performance Bilateral must be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score.

III.13.5.3.2.1. Timing.

A Capacity Performance Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the month associated with the Capacity Performance Bilateral, a Capacity Performance Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Capacity Performance Bilateral may be revised by the parties to the transaction throughout the resettlement process).

III.13.5.3.2.2. Application.

The submission of a Capacity Performance Bilateral to the ISO shall include the following: (i) the resource identification number for the resource transferring its Capacity Performance Score; (ii) the resource identification number for the resource receiving the Capacity Performance Score; (iii) the MW amount of Capacity Performance Score being transferred; (iv) the specific five-minute interval or intervals for which the Capacity Performance Bilateral applies.

III.13.5.3.2.3. ISO Review.

The ISO shall review the information provided in submission of the Capacity Performance Bilateral, and shall reject the Capacity Performance Bilateral if any of the provisions of this Section III.13.5.3 are not met.

III.13.5.3.3. Effect of Capacity Performance Bilateral.

A Capacity Performance Bilateral does not affect in any way either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Capacity Performance Bilateral is to modify the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Conditions subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments as described in Section III.13.7.2.

III.13.6. 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 with Capacity Supply Obligations.

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.

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 with Capacity Supply Obligations.

III.13.6.1.2.1. Energy Market Offer Requirements.

The Real-Time Energy Market offer requirements in this Section III.13.6.1.2.1 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

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 for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.

- (a) 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.
- (b) 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.
- (c) 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.

III.13.6.1.2.2. Additional Requirements for Certain Import Capacity Resources.

The additional requirements for Import Capacity Resources in this Section III.13.6.1.2.2 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

- (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.13.6.1.2.3. Additional Requirements for Import Capacity Resources at External Interfaces with Enhanced Scheduling.

Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented are subject to the following additional requirements unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1. 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 the requirements in this Section III.13.6.1.2.3 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.

- (a) The resource must comply with all information submittal requirements for Day-Ahead Energy Market Coordinated External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals.
- (b) Where the Import Capacity Resource is physically located in a Control Area with which the New England Control Area has implemented the enhanced scheduling procedures in Section III.1.10.7.A, the resource must comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the native Control Area.
- (c) The resource must notify the ISO of all outages impacting the Capacity Supply Obligation of the resource in accordance with the outage notification requirements in ISO New England Operating Procedures.
- (d) At the time of submittal, each Coordinated External Transaction submitted to the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

III.13.6.1.3. Intermittent Power Resources with Capacity Supply Obligations.

III.13.6.1.3.1. Energy Market Offer Requirements.

Market Participants may submit offers into the Day-Ahead Energy Market for Intermittent Power Resources with a Capacity Supply Obligation. Market Participants are required to submit offers for Intermittent Power Resources with a Capacity Supply Obligation for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day-Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

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 Capacity Resources with Capacity Supply Obligations.

III.13.6.1.5.1. Energy Market Offer Requirements.

- (a) A Market Participant with an Active Demand Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers for its Demand Response Resources into the Day-Ahead Energy Market and Real-Time Energy Market. The sum of the Demand Reduction Offers must be equal to or greater than the Active Demand Capacity Resource's Capacity Supply Obligation whenever the Demand Response Resources are physically available. If the Demand Response Resources are physically available at a level less than the Active Demand Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers will equal that level and shall be offered into both

the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet the following requirement:

- (i) the sum of the Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time plus Minimum Reduction Time plus Minimum Time Between Reductions is less than or equal to 72 hours.
- (b) Seasonal Peak Demand Resources and On-Peak Demand Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.5.2. Requirement that Offers Reflect Accurate Demand Response Resource Operating Characteristics.

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a Demand Response Resource associated with an Active Demand Capacity Resource must reflect the then-known operating characteristics of the resource. Consistent with Section III.1.10.9(d), Demand Response Resources must re-declare to the ISO any changes to offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this requirement shall be subject to economic penalties described in Appendix B.

III.13.6.1.5.3. Additional Requirements for Demand Capacity Resources.

- (a) A Market Participant may not associate an Asset with a non-commercial Demand Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Demand Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.
- (b) If a Demand Capacity Resource has summer Qualified Capacity, a summer Seasonal DR Audit value or summer Passive DR Audit value may be used to verify the commercial capacity of the resource. A winter Seasonal DR Audit value or winter Passive DR Audit value may only be used to verify the winter commercial capacity of the resource.
- (c) For Active Demand Capacity Resources, a summer Seasonal DR Audit value shall be established for use from April 1 through November 30 and a winter Seasonal DR Audit value shall be established for use from December 1 through March 31. The summer or winter Seasonal DR Audit value of an Active

Demand Capacity Resource is equal to the sum of the like-season Seasonal DR Audit values of its constituent Demand Response Resources as determined pursuant to Section III.1.5.1.3.1. The Seasonal DR Audit value of an Active Demand Capacity Resource shall automatically update whenever a new Seasonal DR Audit value is approved for a constituent Demand Response Resource or with changes to the makeup of the constituent Demand Response Resources.

(d) On-Peak Demand Resources and Seasonal Peak Demand Resources shall in addition: (i) comply with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals; and (ii) comply with the auditing and rating requirements as detailed in Sections III.13.6.1.5.4 and III.13.6.1.5.5 and the ISO New England Manuals.

(e) Active Demand Capacity Resources shall in addition: (i) comply with the measurement and verification requirements and the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures; and (ii) comply with the auditing and rating requirements as detailed in Section III.13.6.1.5.5 and the ISO New England Manuals.

III.13.6.1.5.4. On-Peak Demand Resource and Seasonal Peak Demand Resource Auditing Requirements.

(a) A summer Passive DR Audit and a winter Passive DR Audit must be performed by each On-Peak Demand Resource and Seasonal Peak Demand Resource in every Capacity Commitment Period during which the On-Peak Demand Resource or Seasonal Peak Demand Resource has an annual or monthly Capacity Supply Obligation.

(b) Summer Passive DR Audits shall be performed during the summer Passive DR Auditing Period (June 1 through August 31). Winter Passive DR Audits shall be performed during the winter Passive DR Auditing Period (December 1 through January 31).

(c) Passive DR Audits are performed following the request of the Market Participant. Audits will be performed within 20 Business Days of the date requested by the Market Participant.

(d) Audits of an On-Peak Demand Resource are conducted by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the On-Peak Demand Resource during the Demand Resource On-Peak Hours.

(e) Audits of a Seasonal Peak Demand Resource are conducted by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the Seasonal Peak Demand Resource during the Demand Resource Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in a month during the Passive DR Auditing Period, performance during Demand Resource On-Peak Hours in that month may be used,

(f) The Passive DR Audit value of an On-Peak Demand Resource or Seasonal Peak Demand Resource is valid beginning with the month for which performance data is submitted and remains valid until the earlier of: (i) the next like-season Passive DR Audit or (ii) the end of the next like-season Passive DR Auditing Period.

(g) At the request of a Market Participant, an audit may be performed outside of the summer Passive DR Auditing Period or winter Passive DR Auditing Period. Such an audit shall not satisfy the Passive DR Audit requirement, however the results of such an audit conducted during the months of September, October, November, April, or May shall be used in the calculation of the Demand Capacity Resource's summer Passive DR Audit value and the results of such an audit conducted during the months of February or March shall be used in the calculation of the Demand Capacity Resource's winter Passive DR Audit value.

(h) If by August 1 for the summer Passive DR Auditing Period or by January 1 for the winter Passive DR Auditing Period a Market Participant has not requested a Passive DR Audit, the Market Participant shall be deemed to have requested a Passive DR Audit on those respective dates. An On-Peak Demand Resource or Seasonal Peak Demand Resource that does not successfully perform a Passive DR Audit for a Passive DR Auditing Period shall have its audit results set to zero.

III.13.6.1.5.5. Additional Demand Capacity Resource Audits.

The ISO may perform additional audits for a Demand Capacity Resource to establish or verify the capability of the Demand Capacity Resource and its underlying assets and measures. 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 Assets and measures to verify that the reported Assets and measures have been installed and are

operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.

(b) Level 2 Audit: the ISO will establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of the Assets and measures. Such an audit may include a random or select sample of facilities and measures.

A level 1 audit is not required to precede a level 2 audit. If the results of the audit indicate that the demand reduction capability of the Demand Capacity Resource is less than or greater than its most recent like-season Passive DR Audit value or Seasonal DR Audit value, then the Demand Capacity Resource's audit value shall be adjusted accordingly.

III.13.6.1.6. DNE Dispatchable Generator.

III.13.6.1.6.1. Energy Market Offer Requirements.

Beginning on June 1, 2019, Market Participants with DNE Dispatchable Generators with a Capacity Supply Obligation must submit offers into the Day-Ahead Energy Market for the full amount of the resource's expected hourly physical capability as determined by the Market Participant. Market Participants with DNE Dispatchable Generators having a Capacity Supply Obligation must submit offers for the Real-Time Energy Market consistent with the characteristics of the resource. For purposes of calculating Real-Time NCPC Charges, DNE Dispatchable Generators shall have a generation deviation of zero.

III.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 without a Capacity Supply Obligation.

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 may submit an offer into the Real-Time Energy Market. If any portion of the offered energy clears in the Real-Time Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Real-Time Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow ISO dispatch instructions. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.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 without a Capacity Supply Obligation.

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 Capacity Resources without a Capacity Supply Obligation.

III.13.6.2.5.1. Energy Market Offer Requirements.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

Seasonal Peak Demand Resources and On-Peak Demand Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation may submit a Demand Reduction Offer into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer, up to the Maximum Reduction offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation, that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit a Demand Reduction Offer in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.2. Additional Requirements for Demand Capacity Resources Having No Capacity Supply Obligation.

Demand Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

- (a) complying with Section III.13.6.1.5.3(a) and (b) and with the auditing and rating requirements described in Section III.13.6.1.5.5 and the ISO New England Manuals; and

(b) for Active Demand Capacity Resources, complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) for Active Demand Capacity Resources, complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Active Demand 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 Capacity Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7.

III.13.6.4. ISO Requests for Energy.

The ISO may request that an Active Demand Capacity Resource or a 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. 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.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1, as adjusted to account for peak energy rents as described in Section III.13.7.1.2.

III.13.7.1.1. Monthly Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period based on the following amounts:

(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 of a New Generating Capacity Resource that has cleared in the Forward Capacity Auction and 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, 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 by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated

with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to 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.13.7.1.2 Peak Energy Rents.

Capacity Base Payments to resources with Capacity Supply Obligations, except for (1) On-Peak Demand Resources, (2) Seasonal Peak Demand Resources, and (3) New Generating Capacity Resources that have cleared in the Forward Capacity Auction and have completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service are not able to achieve Commercial Operation, 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. Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied.

III.13.7.1.2.1 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:

$$\text{Hourly PER}(\$/\text{kW}) = [\text{LMP} - \text{Strike Price}] * [\text{Scaling Factor}] * [\text{Availability Factor}]$$

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 Capacity 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.13.7.1.2.2. Monthly PER Application.

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 the Average Monthly PER multiplied by the resource's Capacity Supply Obligation for the Obligation Month (less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource); provided, however, that in no case shall a resource's PER deduction for an Obligation Month be less than zero or greater than the product of the resource's Capacity Supply Obligation and the relevant Forward Capacity Auction Capacity Clearing Price.

III.13.7.1.3. Export Capacity.

If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

Charge Amount to Resource Exporting = [Capacity Clearing Price_{location of the interface} - Capacity Clearing Price_{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_{location of the interface} - Capacity Clearing Price_{location of the resource}] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.5.1.

III.13.7.1.4. [Reserved.]

III.13.7.2 Capacity Performance Payments.

III.13.7.2.1 Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement; (ii) the system-wide Ten-Minute Non-Spinning Reserve requirement; or (iii) the local Thirty-Minute Operating Reserve requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type.

- (a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Real-Time Reserve Designation (including any regulation capability available but not used for energy) during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Real-Time Designation (including any regulation capability available but not used for energy) during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.
- (b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered (but not less than zero) during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource,

then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the resource's Average Hourly Output or Average Hourly Load Reduction, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(d) A Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the resource's Average Hourly Output or Average Hourly Load Reduction, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(e) [Reserved.]

(f) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Real-Time demand reduction of each associated Demand Response Resource (where the MWhs of reduction, other than the MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses) plus the resource's Real-Time Reserve Designation (adjusted as described in III.9.6.5(h)).

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

$$(\text{Load} + \text{Reserve Requirement}) / \text{Total Capacity Supply Obligation}$$

(a) If the Capacity Scarcity Condition is a result of a violation of the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning Reserve requirement during the interval plus the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval.

(b) If the Capacity Scarcity Condition is a result of a violation of the system-wide Ten-Minute Non-Spinning Reserve requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning Reserve requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval.

(c) If the Capacity Scarcity Condition is a result of a violation of the local Thirty-Minute Operating Reserves requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero).

Reserve Requirement = the local Thirty-Minute Operating Reserve requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the local Thirty-Minute Operating Reserves requirement and either the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement or the system-wide Ten-Minute Non-Spinning Reserve requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(c).

(ii) In any Capacity Zone subject to both the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement and the system-wide Ten-Minute Non-Spinning Reserve requirement, but not to Reserve Constraint Penalty Factor pricing associated with the local Thirty-Minute Operating Reserves requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval minus the product of the resource's Capacity Supply Obligation and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, if the Capacity Scarcity Condition occurs in an interval outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided and Capacity Supply Obligation associated with any On-Peak Demand Resource or Seasonal Peak Demand Resource comprised exclusively of Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be \$2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be \$3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be \$5455/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

III.13.7.3.1 Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month).

III.13.7.3.2 Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

$$\text{MaxCSO} \times [3 \text{ months} \times (\text{FCACP} - \text{FCASP}) - (12 \text{ months} \times \text{FCACP})]$$

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCACP = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCASP = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments.

For each type of Capacity Scarcity Condition as described in Section III.13.7.2.1 and for each Capacity Zone, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a) and (b) below. Where more than one type of Capacity Scarcity Condition applies, then

the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.

(a) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(a).

(b) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.13.7.4(b)

III.13.7.5. 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 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), less PER adjustments for resources in the zone as defined in Section III.13.7.1.2, and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity 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.13.7.5.1. 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; load that is modeled as an Asset Related Demand or discrete load asset and is exclusively related to an Alternative Technology Regulation Resource following AGC dispatch instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A 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 load serving entity's Capacity Requirement will not be reconstituted to include the demand reduction of a Demand Capacity Resource or Demand Response Resource.

III.13.7.5.1.1. 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.13.7.5.1.2. 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.13.7.5.1.3. 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.13.7.5.2. 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.13.7.5.3.

III.13.7.5.3. Capacity Transfer Rights.

III.13.7.5.3.1. 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.13.7.5.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER.

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.13.7.5.3.2(c), III.13.7.5.3.4, and III.13.7.5.3.6 shall be calculated as the product of: (i) the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to “Inadequate Supply” or “Insufficient Competition”) that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015 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)), or, if applicable, minus the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to “Inadequate Supply” or “Insufficient Competition”) that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015 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.13.7.5.3.2.

III.13.7.5.3.2. 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.13.7.5.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface.** The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface.** Except as provided in Section III.13.7.5.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

(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.13.7.5.3.6. 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.13.7.5.3.3. 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.13.7.5.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.5.3.4. 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.13.7.5.3.2.

(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.13.7.5.3.2.

III.13.7.5.3.5. [Reserved.]

III.13.7.5.3.6. 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	Winter
									(MW)	(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.13.7.5.4. 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.

III.13.8. Reporting and Price Finality

III.13.8.1. Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto.

(a) For each Forward Capacity Auction, no later than 20 Business Days after the issuance of retirement determination notifications described in Section III.13.1.2.4(a), the ISO shall make a filing with the Commission pursuant to Section 205 of the Federal Power Act describing the Permanent De-List Bids and Retirement De-List Bids. The ISO will file the following information confidentially: the determinations made by the Internal Market Monitor with respect to each Permanent De-List Bid and Retirement De-List Bid, and supporting documentation for each such determination. The confidential filing shall indicate those resources that will permanently de-list or retire prior to the Forward Capacity Auction and those Permanent De-List Bids and Retirement De-List Bids for which a Lead Market Participant has made an election pursuant to Section III.13.1.2.4.1.

(b) The Forward Capacity Auction shall be conducted using the determinations as approved by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

(c) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), and (viii) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), and (viii) shall be published by the ISO no later than 15 days after the Forward Capacity Auction), with the exception of de-list bid price information, which shall remain confidential):

(i) which Capacity Zones shall be modeled in the Forward Capacity Auction;

(ii) the transmission interface limits as determined pursuant to Section III.12.5;

(iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

(iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;

(v) [reserved];

(vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;

(vii) the Internal Market Monitor's determinations regarding each requested offer price from a new resource submitted pursuant to Section III.13.1.1.2.2.3 or Section III.13.1.4.1.1.2.8, including information regarding each of the elements considered in the Internal Market Monitor's determination of expected net revenues (other than revenues from ISO-administered markets) and whether that element was included or excluded in the determination of whether the offer is consistent with the resource's long run average costs net of expected net revenues other than capacity revenues;

(viii) the Internal Market Monitor's determinations regarding offers or Static De-List Bids, Export Bids, and Administrative De-List Bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the Internal Market Monitor-determined prices established for any Static De-List Bids, Export Bids, and Administrative De-List Bids as described in Section III.13.1.2.3.2 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 filing shall identify to the extent possible the components of the bid which were accepted as justified, and shall also identify to the extent possible the components of the bid which were not justified and which resulted in the Internal Market Monitor establishing an Internal Market Monitor-determined price for the bid;

(ix) which existing resources are qualified to participate in the Forward Capacity Auction (this information will include resource type, capacity zone, and qualified MW); and

(x) aggregate MW from new resources qualified to participate in the Forward Capacity Auction and aggregate de-list bid amounts.

(d) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(c) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4(b) and III.13.1.3.5.7 must be filed with the Commission no later than 15 days after the ISO's submission of the informational filing. If the Commission does not issue an order within 75 days after the ISO's submission of the informational filing that directs otherwise, the determinations contained in the informational filing shall be used in conducting the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within 75 days after the ISO's submission of the informational filing, the Commission does issue an order modifying one or more of the ISO's determinations, then the Forward Capacity Auction shall be conducted no earlier than 15 days following that order using the determinations as modified by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Facility, as defined in Schedule 22 or Schedule 25 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity Auction subject to a Long Lead Time Facility with the higher queue priority. The filing shall also

enumerate bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.

(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO's filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.

(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.

III.14 Regulation Market.

For purposes of this Section III.14, the settlement interval is every five minutes. If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.14.1 Regulation Market System Requirements.

The Regulation Capacity Requirement and Regulation Service Requirement are determined based on historical control performance and compliance with NERC and NPCC control standards. The Regulation Capacity Requirement and Regulation Service Requirement will be published on the ISO's website.

During abnormal system conditions, the ISO may deviate from the Regulation Capacity Requirement or Regulation Service Requirement to maintain system reliability.

III.14.2 Regulation Market Eligibility.

To be eligible to provide Regulation, a Resource must satisfy the following conditions:

- (a) Physical Parameters.
 - (i) Automatic Response Rate.
 - (1) The minimum Automatic Response Rate is 1 MW/minute.
 - (ii) Regulation Capacity.
 - (1) The minimum Regulation Capacity of a generating unit will be determined based on unit size and operating characteristics and must be greater than or equal to: (a) 5 megawatts, and; (b) two times the generating unit's AGC SetPoint Deadband plus one.
 - (2) The minimum Regulation Capacity of a Resource that is not a generating unit is no less than one megawatt after aggregation.

- (b) Regulation Technical Requirements.

A Resource providing Regulation must:

 - (i) be located within the New England Control Area.

 - (ii) meet the technical requirements specified in ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands and ISO New England Operating Procedure No. 18, Metering and Telemetry Criteria.

(iii) be capable of receiving and following AGC SetPoints sent electronically at four-second intervals.

(iv) have a demonstrated capability to reliably follow Dispatch Instructions, consistent with normal operating characteristics and physical offer parameters, including Regulation Capacity and Automatic Response Rate. Resources without an operational history of providing Regulation must establish and demonstrate this capability as follows:

(1) Demand Response Regulation Resources, Dispatchable Asset Related Demand, Alternative Technology Regulation Resources and any Resource with less than one-hour sustainability must participate in the Regulation test environment specified in Section III.14.9.

(2) All Resources must satisfy a minimum responsiveness test that demonstrates that a Resource can follow AGC SetPoints.

(c) Aggregation.

Non-generation sub-resources less than one megawatt in size may be aggregated into a single Resource to meet the Regulation Market eligibility requirements specified in Section III.14.2.

A single AGC SetPoint will be sent every AGC cycle to the aggregated Resource. A Market Participant with an aggregated Resource is responsible for management and control of the individual, aggregated sub-resources to ensure an accurate aggregate response to the AGC SetPoint. The sub-resources may be geographically dispersed, provided:

(i) all of the sub-resources are located within the New England Control Area

(ii) the sub-resources are metered and recorded in a manner that allows real-time performance to be measured against Dispatch Instructions and provides for the retention of the recorded information for purposes of verification, accounting for any performance offsets from other loads, generation or devices under the direct or indirect control of the aggregator as specified in ISO New England Operating Procedure No. 18, Metering and Telemetry Criteria.

(iii) communications and metering are installed and tested for each sub-resource in accordance with ISO New England Operating Procedure No. 18, Metering and Telemetry Criteria and ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands.

III.14.3 Regulation Market Offers.

(a) A Market Participant providing Regulation must submit a Supply Offer. The Supply Offer shall remain effective until cancelled or replaced by the Market Participant. The Supply Offer must specify the following offer parameters:

(i) Regulation unit status (available/unavailable)

Regulation unit status for each hour in an Operating Day must be submitted daily prior to the close of the Re-Offer Period. After initial submission, unit status may be modified at any time.

(ii) Regulation High Limit

For generating units, the Regulation High Limit must be less than or equal to a generating unit's Economic Maximum Limit. For Dispatchable Asset Related Demand, the Regulation High Limit must be greater than or equal to a Dispatchable Asset Related Demand's Minimum Consumption Limit.

(iii) Regulation Low Limit

For generating units, the Regulation Low Limit must be greater than or equal to a generating unit's Economic Minimum Limit. For Dispatchable Asset Related Demand, the Regulation Low Limit must be less than or equal to a Dispatchable Asset Related Demand's Maximum Consumption Limit.

(iv) Automatic Response Rate (MW/minute)

(v) Regulation Capacity Offer (\$/MW)

The Regulation Capacity Offer price must be greater than or equal to \$0/MW and may not exceed \$100/MW. A Market Participant may include estimated inter-temporal opportunity costs in its Regulation Capacity Offer price.

(vi) Regulation Service Offer (\$/MW of instructed movement)

The Regulation Service Offer price must be greater than or equal to \$0/MW of instructed movement and may not exceed \$10/MW of instructed movement.

(b) Additional Constraints on Offer Parameters.

(i) Regulation offer parameters that exceed recent historical performance for Regulation Capacity or Automatic Response Rate will be constrained to reflect values consistent with the demonstrated performance of the Resource. The Resource of a Market Participant that submits offer parameters inconsistent with demonstrated performance will be disqualified from selection to provide Regulation until the submitted parameters are modified to be consistent with demonstrated performance.

(ii) A Resource that is dispatchable in the Real-Time Energy Market and providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided as follows: the upper limit of the Resource's energy dispatch range will be reduced by the amount of Regulation Capacity, and the lower limit of the Resource's energy dispatch range will be increased by the amount of Regulation Capacity.

(c) Sustainability.

Regulation Capacity offers for Resources with less than one-hour sustainability will be evaluated in the selection process using a capacity value adjusted to reflect historical performance when dispatched at the non-adjusted value. The adjusted value will account for the Resource's demonstrated ability to follow the AGC dispatch signal over an hour at the offered Regulation Capacity level. The percentage adjustment will be reevaluated periodically to account for changes in the performance of the Resource. Resources with no historical performance record will be evaluated pursuant to the regulation resource test environment specified in Section III.14.9.

Adjusted Regulation Capacity will be used for the purpose of selecting Resources to meet the Regulation Capacity Requirement and for determining Regulation Capacity compensation.

Resources will be dispatched for Regulation in accordance with the unadjusted Regulation Capacity offer parameters.

For a storage-based resource, sustainability is measured based on full rate of charge/discharge starting from a half-full status.

III.14.4 Regulation Market Administration.

A Market Participant may modify Regulation offer parameters at any time, however the offer parameters in place at the start of a settlement interval will remain in effect through the end of the settlement interval.

The most recent offer parameters will be used when new Resources are selected for a new settlement interval.

III.14.5 Regulation Market Resource Selection.

Resources are selected to provide Regulation from eligible and available Resources to meet the Regulation Capacity Requirement and Regulation Service Requirement at the least-cost based on Regulation Capacity Offers, Regulation Service Offers, estimated energy opportunity costs, impacts on system production costs, and operational requirements related to reliability, including a minimum aggregated response rate and minimizing short-term changes in the assignment of Resources to provide Regulation. For the purposes of least-cost Resource selection, the following penalty factors are used for any violation of the Regulation requirements constraint:

- (1)(a) when the Energy Component of the Real-Time Locational Marginal Price at the reference point is at least \$100/MW the penalty factor is \$100/MW plus the Energy Component of the Real-Time Locational Marginal Price at the reference point for each megawatt of Regulation Capacity shortfall, and
 - (b) when the Energy Component of the Real-Time Locational Marginal Price at the reference point is less than \$100/MW the penalty factor is the maximum of either zero or \$100 plus the Energy Component of the Real-Time Locational Marginal Price at the reference point for each megawatt of Regulation Capacity shortfall and:
- (2) \$10/MW for each megawatt of Regulation Service shortfall. In addition, selection will consider opportunity cost sensitivities associated with large changes in the estimated opportunity cost of a Resource due to the shape of the Resource's Supply Offer price curve.

An eligible Resource may be omitted from providing Regulation due to operational restrictions, including, but not limited to, binding transmission constraints, planned shutdown prior to the end of the settlement interval, or known or anticipated system operating conditions.

The ISO may deviate from the market-based Resource selections to maintain system reliability.

If one or more Resources providing Regulation become unavailable, a new selection process may be conducted to obtain the Resources needed to fulfill the Regulation Capacity Requirement and the Regulation Service Requirement and new clearing prices determined pursuant to Section III.14.8(a).

In the event one or more Resources have equivalent least-cost characteristics in the selection process, the Resource with the larger Regulation Capacity value will be selected or, if the Regulation Capacity value is also equal, the Resource with the earliest Supply Offer submission time will be selected.

III.14.6 Delivery of Regulation Market Products.

Resources selected for Regulation are dispatched to reduce the New England Control Area's area control error as needed to ensure reliability and compliance with NERC and NPCC control standards.

Resources that are generating units are dispatched based on relative response rates using multi-valued AGC SetPoints with AGC SetPoint Deadbands. Resources that are not generating units may be dispatched using one of the following methods:

- (a) an energy-neutral trinary dispatch that calculates AGC SetPoints equal to one of the following three values: Regulation High Limit, Regulation Low Limit, and a midpoint between the Regulation High Limit and the Regulation Low Limit;
- (b) a relative response rate dispatch using multi-valued AGC SetPoints with AGC SetPoint Deadbands, or;
- (c) an energy-neutral relative response rate dispatch using multi-valued AGC SetPoints with AGC SetPoint Deadbands.

A Market Participant may change the dispatch method for a non-generating unit. Dispatch methodology may be changed to be effective at the start of every calendar quarter. Requests to change the dispatch method of a non-generating resource must be received no later than 30 Business Days before the requested effective date of the change. Dispatch will be coordinated with the objective of achieving consistent and non-discriminatory treatment of Resources providing similar offer parameters.

AGC SetPoints will be established to cost-effectively meet reliability criteria based on the current area control error, the Automatic Response Rate and offer parameters of the selected Resources, as well as the current and predicted state of the system.

III.14.7 Performance Monitoring.

The performance of a Resource providing Regulation will be monitored in Real-Time. For each settlement interval, a Resource is considered to be non-performing if, after a grace period, the Resource is not responding to AGC SetPoints at a rate at least equal to a percentage of its Automatic Response Rate or outside a tolerance band around the AGC SetPoint that is equal to a percentage of the Regulation Capacity of the Resource. The grace period will be between two and four minutes. The percentage of the

Automatic Response Rate will be between 80 and 95 percent. The percentage of the Regulation Capacity of the Resource will be between 5 and 15 percent. The specific values will be published on the ISO's website.

A Resource that changes its direction of movement in a manner inconsistent with the AGC SetPoint is considered non-performing for the remainder of the settlement interval.

Compensation adjustments for non-performing Resources are addressed in Section III.14.8(b)(iv).

III.14.8 Regulation Market Settlement and Compensation.

(a) Calculation of Regulation Clearing Prices.

(i) Regulation Service clearing prices.

The Regulation Service clearing price is set equal to the highest Regulation Service Offer of the Resources selected to provide Regulation pursuant to Section III.14.5.

(ii) Regulation Capacity clearing prices.

The Regulation Capacity clearing price is set such that total compensation from the Regulation Service clearing price and the Regulation Capacity clearing price will, based on a uniform clearing price applied to all selected Resources, ensure recovery of as-bid costs for Regulation Capacity, estimated Regulation Service, estimated energy opportunity costs, and the Resource-specific incremental cost savings payment determined for each Resource for the planned duration of the settlement interval.

The incremental cost savings provided by each Resource is assessed by determining the least-cost selection of Resources as specified in Section III.14.5 both with and without the particular Resource. The incremental cost savings for the settlement interval is the estimated total cost of Regulation without the Resource minus the estimated total cost of Regulation with the Resource, including the application of penalty factors to any violation of the Regulation requirements constraint.

(b) Compensation to Regulation Providers.

(i) A Market Participant with a Resource that is selected to provide Regulation and that complies with the dispatch and performance requirements in Section III.14 shall receive:

(1) A capacity payment equal to the amount of Regulation Capacity selected times the Regulation Capacity clearing price.

(2) A service payment equal to the amount of service provided, while the Resource is considered to be performing as specified in Section III.14.7, as measured by the absolute value of the Resource's scheduled movement at the claimed rate of response without delay, in megawatts, toward the AGC SetPoint in response to AGC dispatch signals times the Regulation Service clearing price.

(ii) Calculation of Actual Energy Opportunity Costs.

A Resource-specific Regulation energy opportunity cost for those Resources dispatchable in the Real-Time Energy Market is determined for each five-minute interval that the Resource is selected to provide Regulation. The Regulation energy opportunity cost shall be equal to the product of (i) the absolute value of the deviation of the Resource's dispatch level necessary to follow the ISO's Regulation signals from the Resource's expected dispatch level if it had been dispatched in economic merit order and (ii) the absolute value of the difference between the Real-Time Price at the Node associated with the Resource and the megawatt weighted average Supply Offer or Demand Bid price for the energy associated with the deviation of the Resource's expected dispatch level if it had been dispatched in economic merit order. The Regulation energy opportunity cost for a Resource that is dispatched pursuant to Section III.1.10.9(e) shall be equal to zero for the settlement interval. Regulation energy opportunity costs are only incurred when a Resource is providing Regulation.

(iii) Make-Whole Payment

If revenues from the Regulation Capacity clearing price and the Regulation Service clearing price are insufficient to cover a Market Participant's as-bid costs for the actual Regulation Capacity and the amount of Regulation Service provided during a settlement interval plus actual energy opportunity costs as calculated in Section III.14.8(b)(ii), a make-whole payment will be provided for the period that the Resource is considered to be performing as specified in Section III.14.7.

(iv) Performance Adjustments.

A selected Resource's capacity payment will be reduced to reflect the proportion of time the Resource was determined to be non-performing pursuant to Section III.14.7.

(v) Compensation for Replacement Resources

If system conditions require the ISO to designate additional Resources in order to satisfy Regulation requirements for the remainder of a settlement interval without completing the selection process described in Section III.14.5, compensation for replacement Resources will be made according to the Resource's actual performance using the Regulation Capacity clearing price, the Regulation Service clearing price, and any make-whole payments as specified in Section III.14.8(b)(iii).

(c) Regulation Charges.

Each Market Participant shall have a Regulation charge equal to its pro rata share of the Regulation Capacity Requirement and Regulation Service Requirement for the settlement interval based on the Market Participant's total Real-Time Load Obligation. The total cost of providing Regulation for each settlement interval is charged to Market Participants based on their pro rata share of Real-Time Load Obligation during the period. For the purposes of allocating Regulation charges, the Real-Time Load Obligation of a Dispatchable Asset Related Demand providing Regulation shall be limited to the Minimum Consumption Limit of the Resource. Calculation of Regulation charges shall exclude contributions to Real-Time Load Obligations from Coordinated External Transactions.

(d) Net Energy Settlement for Alternative Technology Regulation Resources.

A Market Participant with an Alternative Technology Regulation Resource that is interconnected and metered at a single location may register the resource as a combination of the following asset types for the purpose of regulation energy market settlement:

1) an Alternative Technology Regulation Resource for the settlement of regulation capacity and regulation service;

2) a Settlement-Only Generator, if not greater than or equal to 5 MW, or otherwise a non-dispatchable, non-regulation capable Generator Asset for settlement of net energy injections that result from following AGC dispatch instructions;

3) an Asset Related Demand for settlement of net energy consumption; and

4) a load asset for settlement of net energy consumption for which the Real-Time Load Obligation is separately reported to the ISO.

III.14.9 Regulation Market Testing Environment.

The ISO administers a regulation resource test environment that allows Market Participants to evaluate or demonstrate the performance of Resources without an operational history of providing Regulation prior to participation in the Regulation Market.

Resources providing Regulation under the regulation resource test environment will be compensated for the Regulation Capacity and Regulation Service provided in response to AGC SetPoints at the lowest of the Regulation Capacity Offer prices and Regulation Service Offer prices offered for any Resource selected during each settlement interval. Resources that are also dispatchable in the Real-Time Energy Market will be compensated for Regulation energy opportunity costs incurred while operating under the regulation resource test environment.

Resources performing a minimal responsiveness test will not be compensated for Regulation.

A Resource may only provide Regulation under the regulation test environment until sufficient operational information has been collected to verify reasonable operating parameters for the Resource or to determine that the Resource does not meet the eligibility requirements necessary to participate in the Regulation Market.

SECTION III

MARKET RULE 1

APPENDIX A

**MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION**

APPENDIX A
MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this *Appendix A*.

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this *Appendix A* shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this *Appendix A*. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this *Appendix A*.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this *Appendix A*, the provisions of *Appendix A* shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III.A.17.3 are also part of the Participants Agreement and cannot be modified in either *Appendix A* or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this *Appendix A* are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

- (a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this *Appendix A*). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its

identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

- (b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.
- (c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the External Market Monitor shall perform the following functions:

- (a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this *Appendix A*, in accordance with the provisions of Section III.A.17 of this *Appendix A*.

- (c) Conduct evaluations and prepare reports on its own initiative or at the request of others.
- (d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this *Appendix A*.
- (f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.
- (g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this *Appendix A*, as appropriate.
- (h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the Internal Market Monitor shall perform the following functions:

- (a) Maintain *Appendix A* and consider whether *Appendix A* requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.
- (b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this *Appendix A*.
- (c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this *Appendix A*.
- (d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this *Appendix A*.
- (e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.
- (g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this *Appendix A*.
- (h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

- (i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this *Appendix A*.
- (j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this *Appendix A* are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

- (i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.
- (ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.
- (iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this *Appendix A*.
- (iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this *Appendix A*.
- (v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend *Appendix A* as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of

the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

- (i) Anti-competitive gaming of Resources;
- (ii) Conduct and market outcomes that are inconsistent with competitive markets;
- (iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;
- (iv) Actions in one market that affect price in another market;
- (v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this *Appendix A*, interfere with efficient market operation, both short-run and long-run; and
- (vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this *Appendix A*. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this *Appendix A*. If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

- (l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.
- (m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with *Appendix B* of this Market Rule 1.

- (n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this *Appendix A* for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule 1 (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this *Appendix A*. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this *Appendix A*, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under *Appendix B* of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

- (a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:
- (b) Notwithstanding the foregoing or any other provision of this *Appendix A*, and as more fully described in Section III.B.3.2.6 of *Appendix B* to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this *Appendix A*, it may make a filing under §205 of the Federal Power Act (“§205”) with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor’s justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this *Appendix A* or in *Appendix B* to this Market Rule 1.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant. In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this *Appendix A*, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this *Appendix A* for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

- (a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.
- (b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer

or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus \$2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1 or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2

2 or more	6
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III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

- (a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
- (b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,
- (c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
- (d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

- (a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
- (b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

- (c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

- (a) all Supply Offer parameters shall be reviewed for economic withholding;
- (b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;
- (c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

- (a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;
- (b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

- (a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;
- (b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than \$25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

- (a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
- (b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or \$100/MWh, whichever is lower. Offer block prices below \$25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or \$100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or \$25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or \$25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

- i. local first contingency;
- ii. local second contingency;
- iii. VAR or voltage;
- iv. distribution (Special Constraint Resource Service);
- v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

- (a) If the Resource is starting from an offline state, the Start-Up Fee;
- (b) The sum of the No Load Fees for the Commitment Period; and
- (c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 “General Threshold Energy Mitigation” or III.A.5.5.2 “Constrained Area Energy Mitigation” is in effect for the following duration:

- (a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:
 - i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,
 - ii. for constrained area energy mitigation, the Resource is not located within a constrained area.
- (b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 “Constrained Area Energy Mitigation”), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 “Manual Dispatch Energy Mitigation” is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource’s Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 “General Threshold Commitment Mitigation”, III.A.5.5.5 “Constrained Area Commitment Mitigation”, or III.A.5.5.6 “Reliability Commitment Mitigation” is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 “Start-Up Fee and No-Load Fee Mitigation” is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as

part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

- (a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.
- (b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.
- (c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Supply Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of a Supply Offer according to the following hierarchy, under which the first method that can be calculated is used:

- (a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
- (b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
- (c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

- (a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
- (b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
- (c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
- (d) For any Operating Day for which, during the previous 90 days:
 - (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
 - (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
 - (iii) The Market Participant submits a fuel price pursuant to Section III.A.3.4.

For the purposes of this subsection:

- i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.
 - ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.
 - iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.
 - iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.
- (e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.
- (f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:
 - (i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,
 - (ii) No-Load Fee or its corresponding fuel blends,
 - (iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,
 - (iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and
 - (v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant through the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

- (a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".
- (b) Costs must be documented.
- (c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible.
- (d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.
- (e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:
 - i. Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected

natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and

- ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy:

$(\text{incremental heat rate} * \text{fuel costs}) + (\text{emissions rate} * \text{emissions allowance price}) + \text{variable operating and maintenance costs} + \text{opportunity costs.}$

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

- (a) emissions limits;
- (b) water storage limits; and,
- (c) other operating permits that limit production of energy.

No-Load:

$(\text{no-load fuel use} * \text{fuel costs}) + (\text{no-load emissions} * \text{emission allowance price})$
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up:

$(\text{start-up fuel use} * \text{fuel costs}) + (\text{start-up emissions} * \text{emission allowance price}) + \text{start-up variable and maintenance costs} + \text{other start-up costs that are not fuel, emissions or variable and maintenance costs.}$

III.A.8. Determination of Offer Competitiveness During Capacity Scarcity Condition.

The Internal Market Monitor shall evaluate the competitiveness of the Supply Offer of each Resource with a Capacity Supply Obligation that is off-line during a Capacity Scarcity Condition, as described

below. The evaluation for competitiveness shall be performed on Supply Offers in the Day-Ahead Energy Market and on Supply Offers in the Real-Time Energy Market. For purposes of these evaluations, Reference Levels are calculated using the cost-based method specified in Section III.A.7.5. The Real-Time Energy Market evaluation uses the final Supply Offer in place for the hour.

- (a) Hours Evaluated. For Supply Offers in the Day-Ahead Energy Market, competitiveness is evaluated for all hours of the Operating Day during which a Capacity Scarcity Condition occurs. For Supply Offers in the Real-Time Energy Market competitiveness is evaluated for the last hour that the Resource could have been committed to be online at its Economic Minimum Limit at the start of the Capacity Scarcity Condition, taking into account the Resource's Start-Up Time and Notification Time.
- (b) Competitiveness Evaluation of Energy Offer At Low Load.
 - (i) If the Resource is not in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.
 - (ii) If the Resource is in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.
- (c) Competitiveness Evaluation of Energy Offer Above Low Load. If a Supply Offer evaluated for competitiveness pursuant to Section III.A.8 (b) above is competitive for an hour, then the energy price parameter for each incremental Supply Offer block above the Resource's Economic Minimum Limit shall be evaluated for competitiveness using the thresholds identified in Section III.A.5.5.1.2, for Resources not in a constrained area, and the thresholds identified in Section III.A.5.5.2.2, for Resources in a constrained area, in order of lowest energy price to highest energy price. If any Supply Offer block is non-competitive, then that block and all blocks above it shall be non-competitive, and all blocks below it shall be competitive.
- (d) Low Load Cost test. Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit for its Minimum Run Time, is calculated as the sum of:
 - i. The Start-Up Fee (cold start);
 - ii. The sum of the No Load Fees for the Resource's Minimum Run Time; and
 - iii. The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Resource's Minimum Run Time.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer Block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer Block.

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor the Energy Market as outlined below:

- (a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.
- (b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$$(\text{LMP}_{\text{real time}} / \text{LMP}_{\text{day ahead}}) - 1.$$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

- (i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.
- (ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.
- (iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England

Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

- (a) [Reserved].
- (b) Section III.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.
- (c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.
- (d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.

- (e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.
- (f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

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 Market Participant in accordance with Section III.A.3 of this *Appendix A*. 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 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer *Appendix B* in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.

Article 5 of the form of Cost-of-Service Agreement in *Appendix I* to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Filing Right.

If either

- (a) as a result of mitigation applied to a Resource under this *Appendix A* for all or part of one or more Operating Days, or
- (b) in the absence of mitigation, despite having submitted a Supply Offer at the Energy Offer Cap,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for the hours of the Operating Day during which the Supply Offer was mitigated or during which the Resource was operated at the Energy Offer Cap, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having submitted a Supply Offer at the Energy Offer Cap, costs incurred for the duration of the period of time for which the Resource was operated at the Energy Offer Cap.

III.A.15.2. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating

the Resource exceeded the costs as reflected in the Supply Offer at the Energy Offer Cap; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.

III.A.15.4. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in *Appendix D* to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.
- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully

challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this *Appendix A*, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

- (a) the opportunity costs associated with Demand Reduction Offers;

- (b) the accuracy of Demand Response Baselines;
- (c) the method used to achieve a demand reduction, and;
- (d) the accuracy of metered demand reported to the ISO.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this *Appendix A* and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this *Appendix A*.

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion

of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this *Appendix A*.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of *Appendix A*. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

- (i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.
- (ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.
- (iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.
- (iv) Review and assessment of the effectiveness of *Appendix A* and the administration of *Appendix A* by the Internal Market Monitor for consistency and compliance with the terms of *Appendix A*.
- (v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

- (a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;
- (b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;
- (c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,
- (d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets (“authorized government agencies”). With respect to state regulatory bodies and state attorneys general (“authorized state agencies”), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government

agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as *Exhibit 5*.

III.A.18.2. Additional Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of *Appendix A*, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the

Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

- (B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information
 - (1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);
 - (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
 - (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
 - (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
 - (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;
 - (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
 - (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

- (A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.
- (B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information.
 - (1) A detailed narrative describing the perceived market design flaw(s);
 - (2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;
 - (3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;
 - (4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the twelfth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2021) shall be as follows:

Generating Capacity Resources	
Technology Type	Offer Review Trigger Price (\$/kW-month)
combustion turbine	\$6.503
combined cycle gas turbine	\$7.856
on-shore wind	\$11.025

Demand Capacity Resources - Commercial and Industrial	
Technology Type	Offer Review Trigger Price (\$/kW-month)
Load Management and/or previously installed Distributed Generation	\$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	\$0.000

Demand Capacity Resources – Residential	
Technology Type	Offer Review Trigger Price (\$/kW-month)
Load Management	\$7.559

previously installed Distributed Generation	\$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	\$0.000

Other Resources

All other technology types	Forward Capacity Auction Starting Price
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Where a new resource is composed of assets having different technology types, the resource’s Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders

and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	Index
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"
steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay: <ul style="list-style-type: none"> - Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts - On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
other labor	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: <ul style="list-style-type: none"> - Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts - On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"
fuel inventories	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	Index
labor, administrative and general	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: <ul style="list-style-type: none"> - Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts - On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit

	Price Deflator (GDPDEF)”
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(3) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 above will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub On-Peak electricity prices for the months in the Capacity Commitment Period beginning June 1, 2021, as published by ICE.

(5) Renewable energy credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO’s web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be \$0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the

requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing

market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in

Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

- (a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;
- (b) For each modeled import-constrained Capacity Zone, the greater of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
- (c) For each modeled export-constrained Capacity Zone, the lesser of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone plus, for each external interface connected to the export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Maximum Capacity Limit of the export-constrained Capacity Zone, and;
- (d) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

- (e) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone;
and

- (f) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

- (a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.
- (b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Capacity Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import

Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

- i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than
- ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then
- iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

- iv. the Lead Market Participant's annual capacity revenue from the Lead Market

Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

- v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.
- vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

SECTION III

MARKET RULE 1

APPENDIX E

[RESERVED]

SECTION III
MARKET RULE 1

APPENDIX F
NET COMMITMENT PERIOD COMPENSATION ACCOUNTING

APPENDIX F
NCPC ACCOUNTING
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NCPC ACCOUNTING

III.F.1. General.

For purposes of NCPC calculations:

- a. Effective Offers.** An Effective Offer for a Resource is (1) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to commit the Resource and (2) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to dispatch the Resource at a Desired Dispatch Point above its Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit, and is subject to the following conditions:
- i. The Effective Offer used in making the decision to commit the Resource establishes the parameters used for NCPC calculations, including the quantity and price pairs for output, demand reduction, or consumption up to the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit; the Start-Up Fee, No-Load Fee, or Interruption Cost; and the operating limits.
 - ii. In the event the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit is increased after the decision to commit the Resource, the energy price parameter for output, demand reduction, or consumption at the Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit used in making the decision to commit the Resource will be applied as the energy price parameter for additional output, demand reduction, or consumption up to the increased Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit.
 - iii. In the event a Minimum Generation Emergency is declared, the Economic Minimum Limit will be replaced with the Emergency Minimum Limit for purposes of determining the energy price parameter of the Effective Offer.
 - iv. The Effective Offer takes account of mitigation applied to the Supply Offer, whether performed prior to or after the commitment or dispatch decision is made.
 - v. The Effective Offer takes account of a reduction in the energy price parameter, the Start-Up Fee, the No-Load Fee, or the Interruption Cost in a Supply Offer or Demand Reduction Offer; or an increase in the energy price parameter of a Demand Bid that is made prior to the end of the Resource's Commitment Period.
 - vi. In the event the ISO approves the Resource's synchronization to the system as a Pool-Scheduled Resource earlier than its scheduled time, the Effective Offer takes account of the

lesser of the energy price parameter, the Start-Up Fee and the No-Load Fee in place for the scheduled Commitment Period or the actual early release-for-dispatch time.

- vii. A Resource that is online providing synchronous condensing is considered to be in a hot temperature state for the purpose of determining the Start-Up Fee for the Effective Offer when the Resource is requested to switch from synchronous condensing to provide energy.

b. Treatment of Self-Schedules.

- i. In the Day-Ahead Energy Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to \$0, a No-Load Fee equal to \$0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to the minimum of the Energy Offer Floor and the Day-Ahead Price; or, in the case of a DARD Pump, is treated as having a Demand Bid with an energy price parameter for consumption up to its Minimum Consumption Limit equal to the maximum of the Energy Offer Cap and the Day-Ahead Price. Any amounts (MW) offered or bid above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid.
- ii. In the Real-Time Energy Market, a Resource that is committed as a Self-Schedule is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to \$0, a No-Load Fee equal to \$0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to \$0/MWh; or (ii) as having a Demand Bid for consumption up to the Minimum Consumption Limit at the Energy Offer Cap. Any amounts (MW) offered above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid. For any hour for which a Resource is dispatched pursuant to Section III.1.10.9(e), the Start-Up Fee and No-Load Fee are equal to \$0.
- iii. If the Resource's Supply Offer contains a Self-Schedule for fewer contiguous hours than its Minimum Run Time, the minimum number of additional hours required to satisfy the Resource's Minimum Run Time will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market. If the Resource is committed for one or more hours immediately prior to and contiguous with the Self-Schedule, the hours of that prior Commitment Period will be counted toward satisfying the Resource's Minimum Run Time before hours subsequent to the Self-Schedule are counted. If the Resource's Supply Offer contains two Self-Schedules separated by less than the Resource's Minimum Down Time, the

hours between the two Self-Schedules will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market.

- c. **Sub-Hourly Intervals.** If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.
- d. **Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Minimum Run Time or Minimum Reduction Time Carries Into Second Operating Day.** If a Resource that is committed in either (i) the Day-Ahead Energy Market, or (ii) the Resource Adequacy Analysis prior to the start of the Operating Day must continue to operate across an Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for hour ending 24 of the Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day. If a Resource that is committed during the Operating Day must continue to operate across the Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the second Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day.
- e. **Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Committed Prior to Day-Ahead Energy Market.** If a Resource is committed for an Operating Day prior to the Day-Ahead Energy Market, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the Operating Day at the time of the commitment is used to establish the Effective Offer for the period of the commitment.
- f. **Eligibility for NCPC Credits When Performing Audits or Facility and Equipment Testing.** The Real-Time NCPC Credit calculation for a Resource performing an audit uses the Start-Up Fee, No-Load Fee, Interruption Cost, Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction in the Effective Offer applicable to the Commitment Period during which the audit is conducted, and does not take account of any increases to the Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction value that take place in the course of the audit.

Market Participants are not eligible for NCPC Credits when conducting audits or Facility and Equipment Testing under the following conditions:

- i. When a Market Participant requests that some hours of the commitment of a Pool-Scheduled Resource be used to satisfy an audit, and the Market Participant has changed the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit for those hours for the purpose of conducting the audit, the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- ii. When a Market Participant Self-Schedules a Resource to perform the audit, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the Self-Schedule and is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- iii. When a Market Participant requests that an audit be performed that requires the ISO to dispatch the Resource for the audit without advance notice to the Market Participant, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment or Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- iv. When an ISO-Initiated Claimed Capability Audit is performed pursuant to III.1.5.1.4, the Market Participant is not eligible for Real-Time Commitment NCPC Credits or Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted if both of the following are true:
 1. the Resource had a summer or winter Seasonal Claimed Capability or Seasonal DR Audit value equal to 0 MW at the beginning of the current Capability Demonstration Year, and
 2. the ISO Initiated Claimed Capability Audit is the first Claimed Capability Audit that the Resource performs during that Capability Demonstration Year.
- v. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Pool-Scheduled Resource, the Economic Minimum Limit (or Minimum Consumption Limit for a DARD Pump) in place at the time of the commitment decision is used for calculating Real-Time Commitment NCPC Credits and the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.

- vi. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Resource that Self-Scheduled, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment and is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.
- g. Coordinated External Transactions are Not Eligible for NCPC and are excluded from NCPC Charges.** Notwithstanding anything to the contrary in this Appendix F, Market Participants are not eligible to receive NCPC Credits for Coordinated External Transactions purchases or sales and shall be excluded from all NCPC Charge calculations under this Appendix F.
- h. Demand Response Resource Credit Calculations.** Where indicated in Section III.F.2, the costs and revenues for a Demand Response Resource, other than those associated with Net Supply or Interruption Costs, are increased by average avoided peak distribution losses.
- i. Following Dispatch Instructions.**
 - i. For the purpose of allocating NCPC costs, a Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit greater 50 MWs is considered to be following a dispatch instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 10% above its Desired Dispatch Point and not less than 10% below its Desired Dispatch Point for each interval in the hour. A Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit less than or equal to 50 MWs is considered to be following a Dispatch Instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 5 MWs above its Desired Dispatch Point and is not less than 5 MWs below its Desired Dispatch Point for each interval in the hour. If the Resource violates this criterion in any interval during the hour, the Resource is considered to be not following Dispatch Instructions for the entire hour.
 - ii. DNE Dispatchable Generators are considered to be following Dispatch Instructions if the actual output of the DNE Dispatchable Generator is at or below its Do Not Exceed Dispatch Point.

III.F.2. NCPC Credits

III.F.2.1 Day-Ahead Energy Market NCPC Credits

III.F.2.1.1. Eligibility for Credit. A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a DARD Pump with a Demand Bid that clear the Day-Ahead Energy Market in an hour is eligible for Day-Ahead Energy Market NCPC Credits for the hour.

III.F.2.1.2. Settlement Period. For a Generator Asset, a Demand Response Resource, or a DARD Pump, for purposes of calculating Day-Ahead Energy Market NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day for which a Resource has cleared in the Day-Ahead Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator or to or from a Fast Start Demand Response Resource, or any time a DNE Dispatchable Generator's operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation.

III.F.2.1.3. Eligible Quantity. For a Generator Asset, Demand Response Resource, or DARD Pump, the eligible quantity of energy is the amount of energy the Resource clears in the Day-Ahead Energy Market for each hour of the settlement period.

III.F.2.1.3A Hourly Bid. For a DARD Pump, the hourly bid is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each hour of the settlement period.

III.F.2.1.4 Hourly Cost.

- (a) For a Generator Asset, the hourly cost is equal to the energy price parameter for the eligible quantity, the Start-Up Fee and the No-Load Fee as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.
- (b) For a Demand Response Resource, the hourly cost is equal to the energy price parameter for the eligible quantity and the Interruption Cost as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.
- (c) For a DARD Pump, the hourly cost is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity.

III.F.2.1.4.1 For a Generator Asset or a Demand Response Resource, the Start-Up Fee or Interruption Cost is apportioned equally over the hours from the time the Resource is scheduled to begin its commitment through the end of the Commitment Period during which the Minimum Run Time or Minimum Reduction Time is scheduled to expire.

III.F.2.1.4.2 For a Generator Asset or a Demand Response Resource, when the period of hours over which the Start-Up Fee or Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee or Interruption Cost.

III.F.2.1.5 Hourly Revenue. For a Generator Asset or a Demand Response Resource, the hourly revenue is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity for the Resource.

III.F.2.1.6 General Credit Calculation. Except as provided in Section III.F. 2.1.7 below, the Day-Ahead Energy Market NCPC Credit for a Resource, adjusted as described in III.F.1(h), is equal to:

- (a) For a Generator Asset or a Demand Response Resource: the greater of (i) zero, and; (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly revenue for the Resource in all hours of the settlement period, where the costs and revenues of a Demand Response Resource, other than those associated with Interruption Costs, are increased by average avoided peak distribution losses; and
- (b) For a DARD Pump: the greater of (i) zero and (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly bids in all hours of the settlement period.

III.F.2.1.7 Credit Calculation for Fast Start Generators, Flexible DNE Dispatchable Generators, Fast Start Demand Response Resources and DARD Pumps Based on Daily Starts. If the number of daily starts for a Fast Start Generator, Flexible DNE Dispatchable Generator, Fast Start Demand Response Resource or DARD Pump is less than the resource's Maximum Number of Daily Starts, then the resource's Day-Ahead Energy Market NCPC Credit, adjusted as described in III.F.1(h), is calculated as follows:

- (a) For a Fast Start Generator, a Flexible DNE Dispatchable Generator or a Fast Start Demand Response Resource, the Day-Ahead Energy Market NCPC Credit is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for the Resource in an hour minus the hourly revenue for the Resource in that hour.
- (b) For a DARD Pump, the Day-Ahead Energy Market NCPC Credit is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the total hourly cost for the Resource in an hour minus the total hourly bid for the Resource in that hour.

III.F.2.2 Real-Time Energy Market NCPC Credits Real-Time Energy Market NCPC Credits include a Real-Time Commitment NCPC Credit, a Real-Time Dispatch NCPC Credit and a Real-Time Dispatch Lost Opportunity Cost NCPC Credit. For purposes of this Section III.F.2.2, unless otherwise expressly stated, costs and revenues shall be calculated at a five minute interval.

III.F.2.2.1 Eligibility for Credit.

- (a) Commitment and Dispatch Credits – The following Resources are eligible for Real-Time Commitment NCPC Credits and Real-Time Dispatch NCPC Credits for some or all intervals of the hour: (i) a Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; (iii) a DARD Pump with a Demand Bid that has been submitted in the Real-Time Energy Market, or; (iv) a DARD Pump that has been Postured to increase its consumption.
- (b) Dispatch Lost Opportunity Cost Credits - A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a Dispatchable Asset Related Demand with a Demand Bid that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Real-Time Dispatch Lost Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Resource has been Postured or has provided Regulation during the interval.

III.F.2.2.2 Real-Time Commitment NCPC Credits

III.F.2.2.2.1 Settlement Period.

- (a) For Generator Assets, Demand Response Resources, and DARD Pumps, for purposes of calculating Real-Time Commitment NCPC Credits, a settlement period is a period of one or more contiguous intervals in an Operating Day during which a Resource is operating pursuant to one or more commitments in the Day-Ahead Energy Market or Real-Time Energy Market.
- (b) For Generator Assets and Demand Response Resources, a new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.

- (c) For Generator Assets and DARD Pumps, in the event of an interruption in operation of a Resource, operation will be considered contiguous if the Resource returns to operation in accordance with the original commitment issued prior to the interruption.

III.F.2.2.2.2. Eligible Quantity.

III.F.2.2.2.2.A For a DARD Pump, the eligible quantity for each interval is the amount of energy equal to the lesser of its Economic Dispatch Point for that interval and its Metered Quantity For Settlement for the interval.

III.F.2.2.2.2.1.

- (a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy equal to the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval.
- (b) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval, except that Metered Quantity For Settlement is used as the eligible quantity (i) when the Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) when the Resource is ramping from an offline state to be released for dispatch or (iii) after the Resource has been released for shutdown.

III.F.2.2.2.2.2.

- (a) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and its Economic Dispatch Point for the interval.
- (b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is equal to the eligible quantity used to determine interval costs pursuant to (a) above, except that the eligible quantity shall be the Metered Quantity For Settlement if any of the following are true: (i) the Demand Response Resource is not eligible for a

Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time have not concluded, or (iii) the Demand Response Resource has received an instruction to stop reducing demand.

III.F.2.2.2.3. Interval Cost.

- (a) The interval cost for a Generator Asset is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Start-Up Fee and No-Load Fee as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1, III.F.2.2.2.3.2, and III.F.2.2.2.3.3.
- (b) The interval cost for a Demand Response Resource is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Interruption Cost as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1 and III.F.2.2.2.3.2, provided that costs shall be set to \$0 for the interval when there is a negative demand reduction.
- (c) The interval cost for a DARD Pump is the Real-Time Price for the interval multiplied by the eligible quantity. The interval cost is reduced by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval cost is also reduced by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5.

III.F.2.2.2.3.1

- (a) For a Generator Asset, the energy cost for an interval excludes the cost of (a) energy produced when the Resource is ramping from an offline state to be released for dispatch and (b) energy produced after the Resource has been released for shutdown.
- (b) For a Demand Response Resource, the energy cost for an interval excludes the cost of (a) energy produced prior to the conclusion of the Demand Response Resource Start-Up Time and (b) energy produced after the Demand Response Resource has received an instruction to stop reducing demand.

III.F.2.2.2.3.2

- (a) For a Generator Asset, the Start-Up Fee is apportioned equally over the intervals from the time the Generator Asset is released for dispatch through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire, subject to the following conditions:
- (i) The Start-Up Fee is reduced in proportion to the number of minutes after 30 the Generator Asset is released for dispatch (measured from the time the Generator Asset was scheduled to be released for dispatch), divided by the time from when the Generator Asset was scheduled to be released for dispatch through the end of the Commitment Period during which the Minimum Run Time was scheduled to expire.
 - (ii) The Start-Up Fee is excluded from the interval cost calculation if the Generator Asset is synchronized to the system prior to its scheduled synchronization time without the ISO's approval of the Generator Asset's synchronization as a Pool-Scheduled Resource.
 - (iii) The portion of the Start-Up Fee apportioned to any interval during which the Generator Asset is not online because the Generator Asset has tripped is excluded from the interval cost calculation, except in the event the Generator Asset is not online due to a trip that results from equipment failure involving equipment located on the electric network beyond the low voltage terminals of the Generator Asset's step-up transformer. It is the responsibility of the Lead Market Participant for the Generator Asset to inform the ISO at xtrip@iso-ne.com within 30 days that the trip was the result of such a transmission-related event.
 - (iv) The Start-Up Fee is not reduced when the Generator Asset has shutdown with the ISO's approval prior to the end of its Commitment Period.
 - (v) The additional Start-Up Fee for a Generator Asset requested to re-start following a trip is apportioned equally over the remaining intervals of the Commitment Period when the ISO requests a Generator Asset to re-start to complete its Commitment Period.
 - (vi) When the period of intervals over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.
- (b) For a Demand Response Resource, the Interruption Cost is apportioned equally over the intervals from the time the Demand Response Resource Start-Up Time concludes through the end of the Commitment Period during which the Minimum Reduction Time is scheduled to expire, subject to the following conditions:
- (i) The Interruption Cost is reduced in proportion to the number of minutes after 30 the Demand Response Resource begins to provide a demand reduction (measured from the conclusion of the Demand Response Resource Start-Up Time), divided by the time from the conclusion of the

Demand Response Resource Start-Up Time through the end of the Commitment Period during which the Minimum Reduction Time was scheduled to expire.

- (ii) The portion of the Interruption Cost apportioned to any interval during which the Demand Response Resource is not providing a demand reduction because the Demand Response Resource has become unavailable to provide a reduction is excluded from the interval cost calculation.
- (iii) The Interruption Cost is not reduced when the Demand Response Resource has stopped reducing demand with the ISO's approval prior to the end of its Commitment Period. When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.
- (iv) When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.

III.F.2.2.2.3.3. For a Generator Asset for each hour, the No-Load Fee is equally apportioned to each interval in the hour during the period when the Generator Asset is online following its release for dispatch and prior to its release for shutdown. The No-Load Fee is pro-rated for the hour during which the Generator Asset is released for dispatch, the hour during which the Generator Asset is released for shutdown, and any other hour during which the Generator Asset operates for less than 60 minutes.

III.F.2.2.2.3.A Interval Bid. The interval bid for a DARD Pump is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each interval of the settlement period.

III.F.2.2.2.4 Interval Revenue. The interval revenue for a Generator Asset or Demand Response Resource is equal to the Real-Time Price for each interval of the settlement period multiplied by the eligible quantity for the interval. The revenue for an interval is increased by the amount by which the interval revenues in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.4 exceed the interval costs in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.3. The interval revenue is increased by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval revenue is also increased by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5. The revenues when the Generator Asset is ramping from an offline state to be released for

dispatch, or during the Demand Response Resource Start-Up Time, are apportioned equally to the intervals of the Minimum Run Time or Minimum Reduction Time.

III.F.2.2.2.4.1. For a Generator Asset, revenues for output up to the Resource's Economic Minimum Limit in a Self-Scheduled interval, calculated as the Real-Time Price multiplied by the output, are excluded from the revenue for the Real-Time Commitment NCPC Credit calculation.

III.F.2.2.2.4.2. For a Demand Response Resource, revenues shall be set to \$0 for the interval when the Locational Marginal Price is positive and there is a negative demand reduction.

III.F.2.2.2.5 Credit Calculation for Generator Assets and Demand Response Resources. The Real-Time Commitment NCPC Credit for a Generator Asset or a Demand Response Resource, adjusted as described in III.F.1(h) is equal to:

- (a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval revenue for the Resource for the period, plus,
- (b) For each remaining interval of the settlement period following the completion of the Minimum Run Time or Minimum Reduction Time, the greater of ((i) zero, and; (ii) the maximum potential net revenues for the Resource in the period) minus the actual net revenues for the Resource in the period, where
 - (i) The maximum potential net revenue is the maximum accumulated net interval revenue for operating and then shutting down (or, for a Demand Response Resource, reducing demand and then ceasing to reduce demand) during the period.
 - (ii) The actual net revenue is the accumulated net interval revenue over the period.
 - (iii) The net interval revenue is the interval revenues minus interval costs in the period.

III.F.2.2.2.6. [Reserved.]

III.F.2.2.2.7 Credit Calculation for DARD Pumps. The Real-Time Commitment NCPC Credit for a DARD Pump is equal to:

- (a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval bid for the Resource for the period,
plus,
- (b) For each remaining interval of the settlement period following the completion of the Minimum Run Time, the greater of ((i) zero, and; (ii) the maximum potential net benefit for the Resource in the period) minus the actual net benefit for the Resource in the period, where
 - (i) The maximum potential net benefit is the maximum accumulated net interval benefit for operating and then shutting down during the period.
 - (ii) The actual net benefit is the accumulated net interval benefit over the period.
 - (iii) The net interval benefit is the interval bid minus interval cost in the period.

III.F.2.2.2.8 Resources with Commitment in the Day-Ahead Energy Market (other than Fast Start Generators, Fast Start Demand Response Resources, and DARD Pumps).

- (a) For purposes of calculating the interval cost under Section III.F.2.2.2.3, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or DARD Pump) has a commitment in the Day-Ahead Energy Market, the Start-Up Fee, No-Load Fee, Interruption Cost and energy price parameter for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to \$0 for the hour. The Start-Up Fee shall not be set to \$0 in the case when a Resource re-starts at ISO request following a trip.
- (b) For purposes of calculating the interval revenue under Section III.F.2.2.2.4, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or DARD Pump) has a commitment in the Day-Ahead Energy Market, the revenue for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to \$0 for the hour if such revenue is less than \$0.
- (c) Notwithstanding anything to the contrary in this Section III.F.2.2.2, a Generator Asset that cleared in the Day-Ahead Energy Market and performs an audit scheduled by the ISO pursuant to Section III.1.5.2(f) during all or part of its Day-Ahead schedule on a higher-priced fuel than that which formed the basis of the Generator Asset's Supply Offer in the Day-Ahead Energy Market shall receive additional compensation equal to:
 - i. For the MW quantity equal to the lesser of the Generator Asset's actual metered output and Economic Dispatch Point, the difference between 1) the incremental energy audit costs based on

- the Supply Offer 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; and
- ii. The difference between the No-Load Fee based on the Supply Offer using the fuel on which the audit was performed and the No-Load Fee for that same operation as reflected in the Day-Ahead Supply Offer; and
 - iii. Any additional Start-Up Fees incurred as a result of performing the audit.

III.F.2.2.3. Real-Time Dispatch NCPC Credits for Generator Assets and Demand Response Resources.

III.F.2.2.3.1 Settlement Period. For Generator Assets and Demand Response Resources, for purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement for a Resource are each greater than its Economic Dispatch Point, excluding any period of time when:

- (a) For a Generator Asset, the generator is ramping from an offline state to be released for dispatch, and after the generator has been released for shutdown, or
- (b) For a Demand Response Resource, prior to the conclusion of the Demand Response Start-Up Time and after the Demand Response Resource has received a Dispatch Instruction to stop reducing demand.

III.F.2.2.3.2. Eligible Quantity.

III.F.2.2.3.2.1.

- (a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the generator's Economic Dispatch Point for the interval subtracted from the lesser of the generator's Metered Quantity For Settlement or Desired Dispatch Point for the interval.
- (b) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Demand Response Resource's Economic Dispatch Point for the interval subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement and its Desired Dispatch Point for the interval.

III.F.2.2.3.2.2.

- (a) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit is the generator's Metered Quantity For Settlement for the interval minus the generator's Economic Dispatch Point, except that the generator's Economic Dispatch Point subtracted from the lesser of the generator's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval.
- (b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit equals the Demand Response Resource's Metered Quantity For Settlement for the interval minus the Demand Response Resource's Economic Dispatch Point, except that the Demand Response Resource's Economic Dispatch Point subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval.

III.F.2.2.3.3 Interval Cost. For a Generator Asset or a Demand Response Resource, the interval cost is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer and does not include the Start-Up Fee, the No-Load Fee, or the Interruption Cost.

III.F.2.2.3.4 Interval Revenue. For a Generator Asset or a Demand Response Resource, the interval revenue is equal to the Real-Time Price multiplied by the eligible quantity, plus, for a Generator Asset, the portion of regulation opportunity costs attributed to operation in response to Regulation AGC dispatch signals at a level above the Resource's expected economic dispatch level, as specified in Section III.14.8(b)(ii).

III.F.2.2.3.5 Credit Calculation. For a Generator Asset or a Demand Response Resource, the Real-Time Dispatch NCPC Credit in an interval is equal to the greater of (i) zero and (ii) the interval cost minus the interval revenue for the Resource, adjusted as described in III.F.1(h).

III.F.2.2.4 Real-Time Dispatch NCPC Credits for DARD Pumps

III.F.2.2.4.1 Settlement Period. For purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement are each greater than the DARD Pump's Economic Dispatch Point.

III.F.2.2.4.2 Eligible Quantity. The eligible quantity of energy is equal to the greater of (i) zero and (ii) the DARD Pump's Economic Dispatch Point for the interval subtracted from the lesser of the DARD Pump's Metered Quantity For Settlement or Desired Dispatch Point for the interval.

III.F.2.2.4.3 Interval Cost. The interval cost is the Real-Time Price for the interval multiplied by the eligible quantity.

III.F.2.2.4.4 Interval Bid. The interval bid is equal to the energy price parameter for the eligible quantity as reflected in the Demand Bid for each interval of the settlement period.

III.F.2.2.4.5 Credit Calculation. The Real-Time Dispatch NCPC Credit for an eligible DARD Pump in an interval is equal to the greater of: (i) zero, and; (ii) the interval cost minus the interval bid in that interval.

III.F.2.2.5. Real-Time Dispatch Lost Opportunity Cost NCPC Credits

III.F.2.2.5.1. Maximum Net Revenue or Maximum Net Benefit.

- (a) For a Generator Asset or a Demand Response Resource, the maximum net revenue during the interval is the Resource's energy revenue at the Economic Dispatch Point, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point, as described in III.F.1(h).
- (b) For a Dispatchable Asset Related Demand, the maximum net benefit during the interval is the Resource's energy price parameter for the Economic Dispatch Point as reflected in the Demand Bid, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point.

III.F.2.2.5.2. Actual Net Revenue or Actual Net Benefit.

- (a) The actual net revenue for a Generator Asset or Demand Response Resource shall be the sum, adjusted as described in III.F.1(h), of the following two values:
 - (i) the greater of: (1) the energy revenue at the Metered Quantity For Settlement minus the offered energy cost for that quantity and (2) the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity; and
 - (ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.

- (b) The actual net benefit for a Dispatchable Asset Related Demand shall be the sum of the following two values:
- (i) the greater of: (1) the energy price parameter for the Metered Quantity For Settlement as reflected in the Demand Bid minus the offered energy cost for that quantity and (2) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity; and
 - (ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.

III.F.2.2.5.3. Credit Calculation. For a Generator Asset, a Demand Response Resource, or a Dispatchable Asset Related Demand, the Real-Time Dispatch Lost Opportunity Cost NCPC Credit is equal to the greater of: (i) zero; and (ii) the Resource's maximum net revenue or benefit for the interval less its actual net revenue or benefit for the interval.

The Dispatch Lost Opportunity Cost NCPC Credit for a Resource for an interval shall be reduced by the amount of any Rapid Response Pricing Opportunity Cost NCPC Credits for which the Resource is eligible for that interval, but shall be no less than zero.

III.F.2.3. Special Case NCPC Credit Calculations

III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits

III.F.2.3.1.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction imports or Increment Offers at an External Node are eligible for Day-Ahead External Transaction Import and Increment Offer NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.1.2. Hourly Offer. The Day-Ahead offer for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the offer price.

III.F.2.3.1.3. Hourly Revenue. The Day-Ahead revenue for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price.

III.F.2.3.1.4. Credit Calculation. A Day-Ahead External Transaction Import and Increment Offer NCPC Credit for an External Transaction import or Increment Offer, for an hour, is equal to any portion of the Day-Ahead offer in excess of the Day-Ahead revenue for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction import or Increment Offer for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction export or Decrement Bid for the same External Node and hour, the Day-Ahead External Transaction Import and Increment Offer NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction import or Increment Offer at the External Node for the hour that is not offset by the amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour. If multiple External Transaction imports or Increment Offers at an External Node are eligible for a Day-Ahead External Transaction Import and Increment Offer NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction imports and Increment Offers will be offset in order from the highest to the lowest-priced transactions or offers.

III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits

III.F.2.3.2.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction exports or Decrement Bids at an External Node are eligible for Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.2.2. Hourly Bid. The Day-Ahead bid for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the bid price.

III.F.2.3.2.3. Hourly Cost. The Day-Ahead cost for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price at the External Node.

III.F.2.3.2.4. Credit Calculation. A Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for an External Transaction export or Decrement Bid, for an hour, is equal to any portion of the Day-Ahead hourly cost in excess of its Day-Ahead hourly bid for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction export or Decrement Bid for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction import or Increment Offer for the same External Node and hour, the Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour that is not offset by the amount (MW) of the total cleared External Transaction import or Increment Offer at the External Node for the hour. If multiple External Transaction exports or Decrement Bids at an External Node are eligible for a Day-Ahead External Transaction Export and Decrement Bid NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction exports and Decrement Bids will be offset in order from the lowest to the highest-priced transactions or bids.

III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)

III.F.2.3.3.1. Eligibility for Credit. All Market Participants that submit pool-scheduled External Transactions (import or export) are eligible for Real-Time External Transaction NCPC Credits, with the exception of External Transactions to wheel energy through the New England Control Area.

III.F.2.3.3.2. Eligible Quantity.

- (a) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that either (i) did not clear in the Day-Ahead Energy Market, or (ii) cleared in the Day-Ahead Energy Market and the price was subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction.
- (b) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that cleared in the Day-Ahead Energy Market and the price was not subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction in excess of the cleared Day-Ahead scheduled transaction amount.

III.F.2.3.3.3. Hourly Offer. The hourly offer for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval offer, which is calculated by multiplying the eligible quantity by the offer price for the interval.

III.F.2.3.3.4. Hourly Revenue. The hourly revenue for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval revenue, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

III.F.2.3.3.5. Hourly Bid. The hourly bid for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval bid, which is calculated by multiplying the eligible quantity by the bid price for the interval.

III.F.2.3.3.6. Hourly Cost. The Real-Time cost for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval cost, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

III.F.2.3.3.7. Credit Calculation. A Real-Time External Transaction NCPC Credit for an External Transaction import for an hour is equal to any portion of the hourly offer in excess of the hourly revenue. A Real-Time External Transaction NCPC Credit for an External Transaction export for an hour is equal to any portion of the hourly cost in excess of the hourly bid.

III.F.2.3.4. [Reserved.]

III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits

III.F.2.3.5.1. Eligibility for Credit. A Resource that is dispatched as a Synchronous Condenser is eligible for Real-Time Synchronous Condensing NCPC Credits.

III.F.2.3.5.2. Condensing Offer Amount. The condensing offer amount for a Resource is equal to the number of hours that the Resource is dispatched as a Synchronous Condenser in an Operating Day multiplied by the hourly price to condense as specified in the Offer Data for the Resource. For a Resource committed from an offline state to provide synchronous condensing, the condensing offer amount includes the condensing start-up fee as specified in the Offer Data for the Resource. In the event an hourly price to condense or condensing start-up fee is not included in the Offer Data for the Resource for the hours that the Resource is dispatched as a Synchronous Condenser, the value for the parameter will be zero.

III.F.2.3.5.3. Credit Calculation. The Real-Time Synchronous Condensing NCPC Credit for a Resource for an Operating Day is equal to the condensing offer amount for that Operating Day.

III.F.2.3.6. Cancelled Start NCPC Credits

III.F.2.3.6.1. Eligibility for credit. A Pool-Scheduled Generator Asset or Demand Response Resource is eligible for a Cancelled Start NCPC Credit if the ISO cancels its commitment of the Pool-Schedule Resource before a Generator Asset is synchronized to the New England Transmission System, or before a Demand Response Resource has completed its Demand Response Resource Notification Time, except that a Market Participant is not eligible for a credit under the following conditions:

- (a) The start is cancelled before the commencement of the Notification Time or the Demand Response Resource Notification Time;
- (b) The Resource's Notification Time or Demand Response Resource Notification Time as reflected in the Effective Offer is equal to or greater than 24 hours;
- (c) The Generator Asset is synchronized to the New England Transmission System for a Self-Schedule within the period of time equal to the lesser of its Minimum Down Time or 10 hours after receiving the ISO cancelled start order; or
- (d) The Generator Asset fails to meet its scheduled synchronization time and the ISO cancelled start order is issued more than two hours after the Resource's scheduled synchronization time.

III.F.2.3.6.2. Credit Calculation. The Cancelled Start NCPC Credit for a Resource is equal to the Start-Up Fee or Interruption Cost reflected in the Effective Offer multiplied by the percentage of the Notification Time or Demand Response Resource Notification Time, as reflected in the Effective Offer, that the Resource completed prior to the ISO cancelled start order, where:

- (a) The percentage of Notification Time or Demand Response Notification Time completed is equal to the number of minutes after the start of the Notification Time or Demand Response Notification Time the Resource was cancelled divided by the Notification Time or Demand Response Notification Time, and cannot exceed 100%.

III.F.2.3.7. Hourly Shortfall NCPC Credits

III.F.2.3.7.1. Eligibility for Credit. A Generator Asset, Demand Response Resource, or DARD Pump that is pool-scheduled in the Day-Ahead Energy Market is eligible for Hourly Shortfall NCPC Credits for an hour if the ISO (1) cancels its commitment of a non-Fast Start Generator, a non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator; or (2) does not dispatch a Fast Start Generator, a Fast Start Demand Response Resource, a DARD Pump, or a Flexible DNE Dispatchable Generator for the hour; and (3) either the Generator Asset or DARD Pump is offline and available for operation and the generator associated with the DARD Pump is not generating, or the Demand Response Resource has not been dispatched and is available for operation; except that (4) a Market Participant is not eligible for a credit under the following conditions:

- (a) The Resource has been Postured for all or part of the hour;
- (b) The Resource is a Limited Energy Resource that has been Postured during a prior hour in the Operating Day; or
- (c) The Resource is an Intermittent Power Resource that is not a DNE Dispatchable Generator.

III.F.2.3.7.2. Settlement Period. For purposes of calculating Hourly Shortfall NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is eligible for an Hourly Shortfall NCPC Credit. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.

III.F.2.3.7.3. Eligible Quantity. The eligible quantity for each hour of the settlement period is:

- (a) zero for a Fast Start Generator, a Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter, the Start-Up Fee and the No-Load Fee of the Supply Offer, or the total of the energy price parameter and the Interruption Cost of the Demand Reduction Offer, in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market for the hour is greater than the total of the corresponding energy price, Start-Up Fee, No Load Fee, and Interruption Cost parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;
 - i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9(e), the Start-Up Fee, No-Load Fee and energy at the Economic Minimum Limit are equal to \$0, and (2) if the ISO is not able to honor a request to be

dispatched for the hour under Section III.1.10.9(f), the Start-Up Fee and No-Load Fee are equal to \$0 and the energy at the requested dispatch level is the Energy Price Floor.

- (b) zero for a DARD Pump in the event the energy price parameter in the Demand Bid in the Real-Time Energy Market for the consumption cleared in the Day-Ahead Energy Market for the hour is less than the energy price parameter in the Demand Bid in the Day-Ahead Energy Market for the hour.
 - i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9 (e), then the energy price at the Minimum Consumption Limit is equal to the Energy Offer Cap, and; (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9 (f), then the energy price at the requested dispatch level for DARD Pumps is the Energy Offer Cap.
- (c) the Day-Ahead Economic Minimum Limit or Minimum Reduction for a non-Fast Start Generator, non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter of the Supply Offer or Demand Reduction Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market above the Day-Ahead Economic Minimum Limit or Day-Ahead Minimum Reduction for an hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

and if neither (a) nor (b) nor (c) applies, then;

- (d) the minimum of (i) the amount of energy cleared in the Day-Ahead Energy Market for an hour and (ii) the Resource's Economic Maximum Limit, Maximum Reduction, or a Limited Energy Resource limit imposed for the hour in the Real-Time Energy Market.

III.F.2.3.7.4. Credit Calculation (for non-Fast Start Generators, non-Fast Start Demand Response Resources, and non-Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC Credit for a Resource, other than a Fast Start Generator, a Fast Start Demand Response Resource, a DARD Pump, or a Flexible DNE Dispatchable Generator, adjusted as described in III.F.1(h), is equal to:

- (a) the greater of (i) zero and (ii) the total of (the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the Day-Ahead Economic Minimum Limit for the hour or the Day-Ahead Minimum Reduction for the hour) for all hours of the settlement period,

plus

(b) for each hour of the settlement period, for Generator Assets, the greater of (i) zero and (ii) the product of (1) the Real-Time Price minus the Day-Ahead Price for an hour and (2) the eligible quantity minus the Day-Ahead Economic Minimum Limit for the hour; or, for Demand Response Resources, the greater of (i) zero and (ii) the product of (1) the Real Time Price minus the Day-Ahead Price for an hour and (2) the eligible quantity minus the Day-Ahead Minimum Reduction for the hour.

III.F.2.3.7.5. Credit Calculation (for Fast Start Generators, Fast Start Demand Response Resources and Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC Credit for a Fast Start Generator, Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and (ii) the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the eligible quantity for the hour, adjusted as described in III.F.1(h).

III.F.2.3.7.6 Credit Calculation (for DARD Pumps). The Hourly Shortfall NCPC Credit for a DARD Pump is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the Day-Ahead Price minus the Real-Time Price for an hour, multiplied by the eligible quantity for the hour.

III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability

III.F.2.3.8.1. Eligibility for Credit. A Limited Energy Resource is eligible for real-time posturing NCPC credits for any Operating Day during which the Resource has been Postured, when a request to minimize the as-bid production costs of the Resource has been submitted. For purposes of calculating real-time posturing NCPC credits, the Resource is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator. If the Resource is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

III.F.2.3.8.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits for Limited Energy Resources, a settlement period is the period of one or more contiguous hours from the initiation of Posturing through the end of the Operating Day.

III.F.2.3.8.3 Resources Sharing a Single Fuel Source. When Limited Energy Resources that share a fuel source are Postured, for purposes of calculating real-time posturing NCPC credits the energy available to the Postured Resources will be allocated among the Postured Resources sharing the fuel source as indicated by estimates of available energy provided by the Lead Market Participant for each Resource prior to Posturing.

III.F.2.3.8.4. Estimated Replacement Cost of Energy. The estimated replacement cost of energy is (i) the average of the Day-Ahead Prices for hours ending 3 through 5 in the subsequent Operating Day for pumped storage generators, or (ii) the product of the oil index price multiplied by the oil-fired generator proxy heat rate for fuel oil-fired generators, or (iii) zero for Resources other than pumped storage generators and fuel oil-fired generators.

For fuel oil-fired generators, the oil index price is the ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation, and the oil-fired generator proxy heat rate is the average of the heat rate at Economic Min and the heat rate at Economic Max, where the heat rate at Economic Min is, for a Resource, the average hourly energy price parameter of the Supply Offer at the Resource's Economic Minimum Limit at the time of the Posturing decision divided by the oil index price, and the heat rate at Economic Max is, for a Resource, the average hourly energy price parameter of the Supply Offer at the Resource's Economic Maximum Limit at the time of the Posturing decision divided by the oil index price.

III.F.2.3.8.5. Estimated Revenue. The estimated revenue for a Resource is the optimized energy output multiplied by the Real-Time Price for all hours in the settlement period. The optimized energy output is estimated for each hour by allocating the Postured energy to hours that the Resource would have operated had it not been Postured based on Real-Time Prices in the Operating Day, subject to the following conditions:

- (a) the optimized energy output determination will take account of the Resource's Economic Minimum Limit, and Economic Maximum Limit.
- (b) the optimized energy output determination will take account of the estimated avoided cost of replacing energy that is not allocated to any hour and remains available at the end of the Operating Day.
- (c) for non-Fast Start Generators, the optimized energy output is calculated for the contiguous hours from the time the Resource is Postured until the available energy is depleted.

III.F.2.3.8.6. Estimated Avoided Replacement Cost. The estimated avoided replacement cost for an Operating Day is the remaining energy that would have been available at the end of the Operating Day had the Resource operated in accordance with the optimized energy output determination in Section III.F.2.3.8.5, plus any increase in the remaining energy resulting from pumping during the Operating Day after the Resource is Postured, multiplied by the estimated replacement cost of energy.

III.F.2.3.8.7. Actual Revenue. The actual revenue for a Resource is the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the settlement period.

III.F.2.3.8.8. Actual Avoided Replacement Cost. The actual avoided replacement cost for an Operating Day is the actual remaining energy at the end of the Operating Day multiplied by the estimated replacement cost of energy.

III.F.2.3.8.9. Credit Calculation. The real-time posturing NCPC credit for Limited Energy Resources is equal to the greater of (i) zero and (ii) the estimated revenue plus the estimated avoided replacement cost, minus the actual revenue plus the actual avoided replacement cost.

III.F.2.3.9. Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured for Reliability and for Demand Response Resources Postured for Reliability

III.F.2.3.9.1. Eligibility for Credit. Generator Assets (other than Limited Energy Resources) and Demand Response Resources are eligible for real-time posturing NCPC credits for the hours during which the Resource has been Postured.

III.F.2.3.9.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits, a settlement period is an hour during which the Generator Asset or Demand Response Resource is Postured.

III.F.2.3.9.3. Offer Used for Estimated Hourly Revenue and Cost.

(a) For a Generator Asset, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:

- (i) Energy Price: the higher of the energy price parameter specified in (1) the Supply Offer for the hour at the time the ISO Postures the Resource, or (2) the Supply Offer for the hour at the start of the hour;
 - (ii) Start-Up Fee and No Load Fee: for Resources Postured offline, the Start-Up Fee and No-Load Fee specified in the Supply Offer for the hour at the time the Resource is Postured; (iii) for Resources Postured to remain online but reduce output, the Start-Up Fee and No-Load Fee are calculated pursuant to Section III.F.2.2.2.3.
- (b) For a Demand Response Resource, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:
- (i) Energy Price: the higher of the energy price parameter specified in (1) the Demand Reduction Offer for the hour at the time the ISO Postures the Resource, or (2) the Demand Reduction Offer for the hour at the start of the hour;
 - (ii) Interruption Cost: for a Demand Response Resource Postured to a demand reduction of zero MWs, the Interruption Cost specified in the Demand Reduction Offer for the hour at the time the Demand Response Resource is Postured; for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MWs, the Interruption Cost is calculated pursuant to Section III.F.2.2.2.3.

III.F.2.3.9.4. Estimated Hourly Revenue.

- (a) The estimated hourly revenue for a Generator Asset is the optimized energy output multiplied by the Real-Time Price for the hour. The optimized energy output is estimated for each hour by determining where the Resource would have operated had it not been Postured based on Real-Time Prices. The optimized energy output determination will take account of the energy price parameter of the Supply Offer and the Resource's Economic Minimum Limit and Economic Maximum Limit.
- (b) The estimated hourly revenue for a Demand Response Resource is the optimized demand reduction multiplied by the Real-Time Price for the hour, where:
 - (i) The optimized demand reduction is estimated for each hour by determining where the Demand Response Resource would have operated had it not been Postured based on Real-Time Prices. The optimized demand reduction determination will take account of the energy price parameter of the Demand Reduction Offer and the Demand Response Resource's Minimum Reduction and Maximum Reduction.

III.F.2.3.9.5. Estimated Hourly Cost.

- (a) The estimated hourly cost for a Generator Asset is the energy price parameter of the Supply Offer for the optimized energy output for the hour, plus the Start-Up Fee and the No-Load Fee, subject to the following conditions:
- (i) For a Fast Start Generator Postured offline, the Start-Up Fee is included in each hour's cost and is not subject to apportionment;
 - (ii) For a non-Fast Start Generator Postured offline, the Start-Up Fee is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.
- (b) The estimated hourly cost for a Demand Response Resource is the energy price parameter of the Demand Reduction Offer for the optimized demand reduction for the hour (where optimized demand reduction is determined pursuant to Section III.F.2.3.9.4(b)), plus the Interruption Cost, subject to the following conditions:
- (i) For a Fast Start Demand Response Resource Postured to a demand reduction level of zero MWs, the Interruption Cost is included in each hour's cost and is not subject to apportionment;
 - (ii) For a non-Fast Start Demand Response Resource Postured to a demand reduction of greater than zero MWs, the Interruption Cost is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.
- (c) A Generator Asset is treated as a Fast Start Generator and a Demand Response Resource is treated as a Fast Start Demand Response Resource for purposes of determining the estimated hourly cost only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator or non-Fast Start Demand Response Resource. If at the time the Resource is Postured the Generator Asset is offline, or the Demand Response Resource has not been dispatched, then its designation as a Fast Start Generator or Fast Start Demand Response Resource is determined as of the time of the Posturing decision.

III.F.2.3.9.6. Actual Hourly Revenue. The actual hourly revenue for a Generator Asset or a Demand Response Resource is the sum of the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the hour.

III.F.2.3.9.7. Actual Hourly Cost.

- (a) The actual hourly cost for a Resource Postured to remain online but reduce output is the sum of the interval cost, which is the energy price parameter of the Supply Offer for the Metered Quantity For Settlement for the interval, plus the Start-Up Fee and No-Load Fee calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Resource Postured offline is zero.
- (b) The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MWs is the sum of the interval cost, which is the energy price parameter of the

Demand Reduction Offer for the Metered Quantity For Settlement for the interval, plus the Interruption Cost calculated pursuant to pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to zero MWs is zero.

III.F.2.3.9.8. Credit Calculation. The real-time posturing NCPC credit for a Generator Asset (other than a Limited Energy Resource) or a Demand Response Resource is equal to the greater of (i) zero and (ii) the estimated hourly revenue minus the estimated hourly cost, minus the actual hourly revenue minus actual hourly cost, adjusted as described in III.F.1(h).

III.F.2.3.10. Rapid Response Pricing Opportunity Cost NCPC Credits Resulting from Commitment of Rapid Response Pricing Assets

III.F.2.3.10.1. Eligibility for Credit. During any five-minute pricing interval in which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, any Resource that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Rapid Response Pricing Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Resource is non-dispatchable; the Resource has been Postured or has provided Regulation at any time during the hour in which the interval occurs; if the Resource is a Settlement Only Resource, or if the Resource is an External Resource or External Transaction.

III.F.2.3.10.2. Economic Net Revenue or Economic Net Benefit.

- (a) The economic net revenue for a Generator Asset or Demand Response Resource during the pricing interval is the Resource's optimized feasible energy quantity multiplied by the Real-Time Price, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.
- (b) The economic net benefit for a Dispatchable Asset Related Demand during the pricing interval is the Resource's energy price parameter for its optimized feasible energy quantity as reflected in its Demand Bid, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the optimized feasible energy quantity multiplied by the Real-Time Price.
- (c) The optimized feasible energy and reserve quantities are determined consistent with the Resource's offer or bid parameters, and are the energy and reserve quantities that maximize the Resource's economic net revenue or economic net benefit for the pricing interval, without changing the Resource's commitment status.

III.F.2.3.10.3. Actual Net Revenue or Actual Net Benefit.

- (a) The actual net revenue for a Generator Asset or Demand Response Resource is the greater of: (i) the actual energy quantity supplied during the pricing interval multiplied by the Real-Time Price, plus the actual reserve quantity supplied during the pricing interval multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities; and (ii) the dispatched energy quantity multiplied by the Real-Time Price, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.
- (b) The actual net benefit for a Dispatchable Asset Related Demand is the greater of: (i) the energy price parameter for the actual energy quantity consumed as reflected in the Demand Bid, plus the actual reserve quantity supplied multiplied by the Real-Time Reserve Clearing Price, minus the actual energy quantity consumed multiplied by the Real-Time Price, and (ii) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.

III.F.2.3.10.4. Credit Calculation. The real-time Rapid Response Pricing Opportunity Cost NCPC Credit for a Resource is equal to the greater of: (i) zero; and (ii) the Resource's economic net revenue or economic net benefit for the interval less its actual net revenue or actual net benefit for the pricing interval.

III.F.2.4. Apportionment of NCPC Credits. For purposes of this Section III.F.2.4, any values previously established at the five minute level shall be aggregated to create hourly values.

Each of the Day-Ahead Energy Market NCPC Credits for a non-Fast Start Generator, a non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator are apportioned to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue for all hours in the settlement period.

Each of the Real-Time Commitment NCPC Credits is apportioned as follows: (i) for the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the portion of the Commitment Period, and (ii) for all remaining intervals of the settlement period, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the period.

Each of the Hourly Shortfall NCPC Credits for a non-Fast Start Generator, a non-Fast Start Demand Response Resource or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator for energy cleared in the Day-Ahead Energy Market at the Resource's Economic Minimum Limit or Minimum Reduction is apportioned to the hours in which the Real-Time Price exceeds the Day-Ahead Price, for all hours in the settlement period.

The following NCPC credits are assigned to the hours for which the credit was calculated:

- Day-Ahead Energy Market NCPC Credits for Fast Start Generators, Fast Start Demand Response Resources, DARD Pumps, and Flexible DNE Dispatchable Generators, where the daily starts in their Day-Ahead Energy Market schedules are fewer than their Maximum Number of Daily Starts.
- Real-Time Dispatch Lost Opportunity Cost NCPC Credits,
- Real-Time Dispatch NCPC Credits for all Resources,
- Day-Ahead External Transaction Import and Increment Offer NCPC Credits,
- Day-Ahead External Transaction Export and Decrement Bid NCPC Credits,
- Real-Time External Transaction NCPC Credits,
- Hourly Shortfall NCPC Credits for Fast Start Generators, Fast Start Demand Response Resources, DARD Pumps and Flexible DNE Dispatchable Generators,
- Hourly Shortfall NCPC Credits for non-Fast Start Generators, non-Fast Start Demand Response Resources, and DNE Dispatchable Generators that are not Flexible DNE Dispatchable Generators for energy cleared in the Day-Ahead Energy Market above the Resource's Economic Minimum Limit or Minimum Reduction, and
- Rapid Response Pricing Opportunity Cost NCPC Credits as described in Section III.F.2.3.10.

III.F.2.5. NCPC Credit Designation for Purposes of NCPC Cost Allocation. Each hourly credit for Day-Ahead Energy Market NCPC Credits, Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, Day-Ahead External Transaction Import and Increment Offer NCPC Credits, Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, Real-Time External Transaction NCPC Credits, Hourly Shortfall NCPC Credits, and Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured For Reliability and Demand Response Resources Postured For Reliability, and each daily credit for Real-Time Synchronous Condensing NCPC Credits, Cancelled Start NCPC Credits, Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability, and Rapid

Response Pricing Opportunity Cost NCPC Credit is designated as first contingency, second contingency, voltage (VAR), distribution (SCR), ISO initiated audits and Minimum Generation Emergency consistent with the reason provided by the ISO when issuing a Dispatch Instruction for the Resource. If there is more than one reason provided by the ISO when issuing the Dispatch Instruction, the NCPC Credits are divided equally for purposes of the above designations. With the exception of Day-Ahead External Transaction Import and Increment Offer NCPC Credits and Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, the hourly credits are summed to determine the total credits for each NCPC Charge category for a day.

III.F.3. Charges for NCPC

III.F.3.1. Cost Allocation.

III.F.3.1.1 Day-Ahead Energy Market NCPC Cost Allocation. NCPC costs for the Day-Ahead Energy Market are allocated and charged as follows:

- (a) The total NCPC cost for the Day-Ahead Energy Market associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.
- (b) The total NCPC cost for the Day-Ahead Energy Market for resources designated as Special Constraint Resources in the Day-Ahead Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.
- (c) The total NCPC cost for the Day-Ahead Energy Market for resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.
- (d) For each External Node, the total NCPC cost for Day-Ahead External Transaction Import and Increment Offer NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Load Obligations at the External Node for the hour.
- (e) For each External Node, the total Day-Ahead External Transaction Export and Decrement Bid NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Generation Obligations at the External Node for the hour.

- f) All remaining NCPC costs for the Day-Ahead Energy Market (except the NCPC costs for DARD Pumps) are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub).
- g) All remaining NCPC costs for the Day-Ahead Energy Market associated with DARD Pumps are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub) excluding Day-Ahead Load Obligations associated with DARD Pumps.

III.F.3.1.2. Real-Time Energy Market NCPC Cost Allocation. NCPC costs for the Real-Time Energy Market are allocated and charged as follows, subject to the conditions in Section III.F.3.1.3:

- (a) The total NCPC cost for the Real-Time Energy Market associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are allocated and charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.
- (b) The total NCPC cost for the Real-Time Energy Market for resources designated as Special Constraint Resources in the Real-Time Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.
- (c) The total ISO initiated audit NCPC cost for resources performing an ISO initiated audit is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with DARD Pumps.
- (d) The total NCPC cost for resources being postured in the Real-Time Energy Market is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with DARD Pumps.
- (e) The total NCPC cost for Rapid Response Pricing Opportunity Cost NCPC Credit during pricing intervals in which one or more Rapid Response Pricing Asset is committed in the Real-Time Energy Market (and not Self-Scheduled) is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with DARD Pumps.
- (f) The total NCPC cost for the Real-Time Energy Market for resources identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.
- (g) Total Minimum Generation Emergency Credits within a Reliability Region are allocated and charged hourly to Market Participants based on each Market Participant's pro rata share of Real-Time

Generation Obligations, and positive Real-Time Demand Reduction Obligations, excluding that portion of a Market Participant's Real-Time Generation Obligation and Real-Time Demand Reduction Obligation within a Reliability Region that is eligible for a Real-Time Dispatch NCPC Credit pursuant to Section III.F.2.2.3 during a Minimum Generation Emergency.

- (h) The total NCPC cost for Real-Time Dispatch Lost Opportunity Cost NCPC Credits is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with DARD Pumps.
- (i) All remaining NCPC costs for the Real-Time Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of the absolute values of a Market Participant's (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day (excluding certain positive Real-Time Load Obligation Deviations as described in Section III.F.3.1.3(d)); (ii) generation deviations for Pool-Scheduled Resources not following Dispatch Instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following Dispatch Instructions, and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following Dispatch Instructions, including External Resources, in MWhs during the Operating Day; (iii) demand reduction deviations for Pool-Scheduled Demand Response Resources not following Dispatch Instructions; and (iv) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day. The Real-Time deviations calculation is specified in greater detail in Section III.F.3.2.

III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation.

- (a) If a Generator Asset has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.
- (b) If a Demand Response Resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the resource should not be dispatched in order to avoid a Minimum Generation Emergency, the Market Participant will be responsible for all Real-Time Demand Reduction Obligation Deviation charges, but will not incur related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.
- (c) Any difference between the actual consumption (Real-Time Load Obligation) of Dispatchable Asset Related Demands and Dispatchable Asset Related Demand bids that clear in the Day-Ahead Energy

Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation for the purpose of allocating costs for Real-Time Energy Market NCPC Credits.

- (d) In any hour during which a Capacity Scarcity Condition occurs or ISO New England Operating Procedure No. 4 or ISO New England Operating Procedure No. 7 are implemented, any NCPC Charges that would have been allocated pursuant to Section III.F.3.2 to net positive Real-Time Load Obligation Deviations in an affected Load Zone (and related portion of adjacent External Nodes) are instead allocated and charged to Market Participants based on their pro rata share of the sum of their Real-Time Load Obligation (excluding Real-Time Load Obligations associated with a Postured Dispatchable Asset Related Demand Resource) in all the affected Load Zones and (and related portion of adjacent External Nodes) during the affected hour(s). For purposes of this calculation, the ISO shall apportion any Real-Time Load Obligations and Real-Time Load Obligation Deviations at an External Node equally among the Load Zones to which the External Node is interconnected.

III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits.

Each Market Participant's pro-rata share of the Real-Time deviations for Real-Time Energy Market NCPC Credits is the following:

- (a) For each Self-Scheduled Generator Asset, if the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

- (b) For each Self-Scheduled Generator Asset, if the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) or (Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

- (c) For each Self-Scheduled Generator Asset, if the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

plus,

- (d) for each Pool Scheduled Generator Asset:

- (i) If the Generator Asset is not following Dispatch Instructions, has cleared Day-Ahead, has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

- (ii) If the Generator Asset is not following Dispatch Instructions, has cleared Day-Ahead, has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output - cleared Day-Ahead MWh) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

- (e) for each Pool Scheduled Demand Response Resource:

- (i) If the Demand Response Resource is being dispatched, is not following Dispatch Instructions, has cleared Day-Ahead, and has not been ordered to stop reducing demand for reliability purposes: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction – Desired Dispatch Point) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

- (ii) If the Demand Response Resource is unavailable and has cleared Day-Ahead: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction – cleared Day-Ahead MWh) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

- (f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation,

where

- (i) each Market Participant's Real-Time Load Obligation Deviation for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub), and
- (ii) for purposes of calculating a Participant's Real-Time Load Obligation Deviation under this subsection (e), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and
- (iii) External Transaction sales curtailed by the ISO are omitted from this calculation.

plus,

- (g) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation,

Where

- (i) each Market Participant's Real-Time Generation Obligation Deviation at External Nodes for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes, and
- (ii) for purposes of calculating a Participant's Real-Time Generation Obligation Deviation under this sub-section (f), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and
- (iii) External Transaction purchases curtailed by the ISO are omitted from this calculation.

plus,

- (h) the absolute value of the total over all Locations of the Market Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

III.F.3.3 Local Second Contingency Protection Resource NCPC Charges.

Each Market Participant's pro-rata share of the cost for Day-Ahead Energy Market NCPC Credits and Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection is based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region, excluding Real-Time Load Obligations associated with DARD Pumps subject to the following conditions:

- (a) The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating a Market Participant's pro-rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

(b) For hours in which there is an NCPC cost for a resource providing Local Second Contingency Protection and ISO is selling Emergency Energy to an adjacent Control Area, the scheduled amount of Emergency Energy at the applicable External Node will be included in the calculation of a Market Participant's pro rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection as if the Emergency Energy sale were a Real-Time Load Obligation within each affected Reliability Region. The pro rata share calculated for the Emergency Energy transaction shall be included in the charges under an agreement for purchase and sale of Emergency Energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency Energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

External Node Common Name	Associated Transmission Facilities	Reliability Region(s)	Allocator
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390/3016) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-7 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line) Alps – Berkshire Line (393Line) Pleasant Valley – Long Mountain Line (398 Line)	Vermont, Vermont Vermont West Central Massachusetts West Central Massachusetts Connecticut	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
NY NNC External Node	Northport-Norwalk Harbor	Connecticut	100% to Connecticut

External Node Common Name	Associated Transmission Facilities	Reliability Region(s)	Allocator
	(601,602 and 603 Lines)		
NY CSC External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(c) For each month, the ISO performs an evaluation of total Local Second Contingency Protection Resource NCPC Charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph c, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency Energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a DARD Pump.

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge $_{(Reliability\ Region, month)}$ $>$ $.06 \times$ Load Weighted Real-Time LMP $_{(Reliability\ Region, month)}$

Condition 2 – is the Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region, month)}$ $>$ $2 \times$ Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region)}$

Where:

Real-Time Load Obligation $_{(Reliability\ Region, month)}$ equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge $_{(Reliability\ Region, month)}$ equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation $_{(Reliability\ Region, month)}$.

Load Weighted Real-Time LMP_(Reliability Region, month) equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation_(Reliability Region, month).

Local Second Contingency Protection Resource Charge %_(Reliability Region, month) equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP_(Reliability Region, month).

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge %_(Reliability Region) equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge %_(Reliability Region, month) divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge %_(Reliability Region), a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge %_(Reliability Region) value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge_(Reliability Region, month) is triggered.

- (ii) Determination of the portion of Local Second Contingency Protection Resource Charge_(Reliability Region, month) to be reallocated –

Local Second Contingency Protection Resource Charge_(Reliability Region, month) to be reallocated = Real-Time Load Obligation_(Reliability Region, month) X Min (Condition 1 Rate_(Reliability Region, month), Condition 2 Rate_(Reliability Region, month))

Where:

Condition 1 Rate_(Reliability Region, month) equals the Local Second Contingency Protection Resource Charge_(Reliability Region, month) minus .06 times the Load Weighted Real-Time LMP_(Reliability Region, month).

Condition 2 Rate_(Reliability Region, month) equals the Local Second Contingency Protection Resource Charge_(Reliability Region, month) minus 2 times the Twelve Month Rolling Average Local Second

Contingency Protection Resource Charge % (Reliability Region) times the Load Weighted Real-Time LMP (Reliability Region, month).

(iii) Determination of Local Second Contingency Protection Resource Charge (Reliability Region, month) reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

(Real-Time Load Obligation (Participant, Reliability Region, month) / Real-Time Load Obligation (Reliability Region, month)) * Local Second Contingency Protection Resource Charges (Reliability Region, month) to be reallocated

Where:

Real-Time Load Obligation (Participant, Reliability Region, month) equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

(Regional Network Load (Transmission Customer, Reliability Region, month) / Regional Network Load (Reliability Region, month)) * Local Second Contingency Protection Resource Charges (Reliability Region, month) to be reallocated

Where:

Regional Network Load (Reliability Region, month) equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load (Customer, Reliability Region, month) equals:

The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

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