



July 27, 2020

VIA eTARIFF 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. ER20-__-000; Addition of Thirty Minutes to Day-Ahead Energy Market Submission Window

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 submits to the Federal Energy Regulatory Commission (the “Commission”) this transmittal letter and revisions to the ISO’s Transmission, Markets and Services Tariff (the “Tariff”) to extend the Day-Ahead Energy Market offer and bid window so that it closes thirty minutes later in the morning.³ As more fully described in this filing letter and in the attached testimony of Dennis Robinson, (the “Robinson Testimony,” sponsored solely by the ISO), these revisions will afford suppliers additional time to consider more recent

¹ 16 U.S.C. § 824d (2018).

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.

information before finalizing their day-ahead offers and bids. As described in Part IV of this filing letter, the revisions received the unanimous support of NEPOOL stakeholders.

I. DESCRIPTION OF THE FILING PARTIES; COMMUNICATIONS

ISO-NE is the private, non-profit entity that serves as the Regional Transmission Organization (“RTO”) for New England. ISO-NE operates the New England bulk power system and administers New England’s organized wholesale electricity market pursuant to the Tariff and the Transmission Operating Agreement (“TOA”) with the New England Participating Transmission Owners. In its capacity as an RTO, ISO-NE has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 500 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,⁴ 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., et al.*, 109 FERC ¶ 61,147 (2004).

And to NEPOOL as follows:

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II. 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.”⁶ Under Section 205, the Commission “plays ‘an essentially passive and reactive role’”⁷ whereby it “can reject [a filing] only if it finds that the changes proposed by the public utility are not ‘just and reasonable.’”⁸ 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.”⁹ The changes proposed herein “need not be the only reasonable methodology, or even the most accurate.”¹⁰ As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.¹¹

⁵ 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.

⁶ *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002).

⁷ *Id.* at 10 (quoting *Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

⁸ *Id.* at 9.

⁹ *Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

¹⁰ *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

¹¹ *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*, 727 F.2d at 1136).

III. EXPLANATION OF THE CHANGES

As described in the Robinson Testimony, the primary change being made with this filing is extending the Day-Ahead Energy Market offer window so that it closes thirty minutes later in the morning.¹² As a result, the deadline for Market Participants to submit offers or bids in the Day-Ahead Energy Market will be shifted from its current close at 10:00 a.m. to a new close of 10:30 a.m. The ISO is moving the submission deadline later in the morning to address feedback from participants to allow suppliers additional time to consider more recent information before finalizing their day-ahead offers and bids.¹³

The ISO's current Day-Ahead Energy Market timeline was established in May of 2013, when it was revised to better accommodate the fuel procurement activities of gas-fired generators.¹⁴ Under the current timeline, the Tariff requires that Market Participants submit offers and bids in the Day-Ahead Energy Market by 10:00 a.m.,¹⁵ and further requires that the ISO post the day-ahead market results by 1:30 p.m.¹⁶ In 2013, when this schedule was established, the ISO committed to continue to evaluate further improvements to the day-ahead clearing time.¹⁷ If the ISO could improve (that is, decrease) the time required to clear the market, participants could be permitted to submit offers and bids in the day-ahead market later in the day.¹⁸

Some suppliers have requested that the current Day-Ahead Energy Market submission deadline be extended in order to provide additional time to consider more recent information prior to finalizing their day-ahead offers and bids.¹⁹ For example, some participants submitting offers from gas-fired generators have reported to the ISO that a later submission deadline would

¹² See Robinson Testimony at 2.

¹³ See *id.*

¹⁴ See *Order on Proposed Tariff Revisions*, 143 FERC ¶ 61,065 (2013) (accepting NEPOOL's proposal to establish the current 10:00 a.m. deadline to submit offers and bids) ("Order on Day-Ahead Timeline").

¹⁵ See existing Section III.1.10.1A ("[t]he submission of Day-Ahead offers and bids shall occur not later than 10:00 a.m.").

¹⁶ See existing Section III.1.10.8(b) ("[n]ot later than 1:30 p.m. of the day before each Operating Day . . . the ISO shall: (i) post the aggregate Day-Ahead Energy schedule [and] (ii) post the Day-Ahead Prices").

¹⁷ See *Order on Day-Ahead Timeline* at P 35 (referencing the ISO's "commitment to review after a year of implementation the system performance under the day-ahead market schedule changes"); see also *ISO New England Inc., Informational Filing of Day-Ahead Energy Market and Reserve Adequacy Analysis Timing Report*, Docket No. ER13-895 (filed May 23, 2014) at p 3 (the "ISO is continuing to evaluate further improvements to the [Day-Ahead Energy Market] clearing time by enhancing the underlying architecture to utilize parallel computing techniques and speed up the security analysis component and data transfer.").

¹⁸ See Robinson Testimony at 2.

¹⁹ See Robinson Testimony at 3.

allow them to benefit from additional transparency, price discovery, and competition in the natural gas commodity market when formulating their ISO-NE day-ahead energy bids.²⁰ Similarly, participants who transact on the New York-New England interface have reported to the ISO-NE that they would find it beneficial to be able to consider the New York ISO (“NYISO”) day-ahead results when formulating their ISO-NE day-ahead offers.²¹

Since the May 2013 changes to the day-ahead timeline, process and technical improvements have enabled the ISO to decrease the time required to clear, validate, and post the day-ahead market results.²² For example, while the Tariff requires that the ISO post the day-ahead results no later than 1:30 p.m. (three and-a-half hours after the close of the offer and bid submission window), the ISO typically is able to post the day-ahead results earlier, usually between 12:00 p.m. and 1:00 p.m.²³ In fact, since the May 2013 implementation of the current schedule, the ISO has posted day-ahead results within three hours on 93% of days, and since the start of 2019, the percentage of days on which the ISO has posted day-ahead results within three hours has increased to 99.1%.²⁴

Moving the close of the day-ahead submission window later by thirty minutes is the sole substantive change being made with these revisions; the revisions make no other changes to the day-ahead market rules, nor to the re-offer period, nor to any other real-time market activities that occur subsequent to day-ahead market.²⁵ The schedule change is effectuated by the following changes to Section III.1.10.1A, which, in addition to updating the submission window’s closing time to 10:30 a.m., also include slight wording changes for improved clarity:

~~The submission of Market Participants may submit offers and bids in the Day-Ahead Energy Market until 10:30 offers and bids 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.

Finally, the revisions also include two clean-up changes in Section III.1 to fix errors introduced by a misalignment in the filing and effective dates of a 2017 energy offer cap filing²⁶

²⁰ See *id.*

²¹ See *id.*

²² See *id.*

²³ See *id.*

²⁴ See *id.*

²⁵ See Robinson Testimony at 4.

²⁶ See *ISO New England Inc. and New England Power Pool, Market Rule 1 Revisions to Modify Energy Market Offer Caps in Compliance With Order No. 831*, Docket No. ER17-1565 (filed May 8, 2017) (“Offer Cap Filing”).

and a subsequent Price Responsive Demand filing.²⁷ The Offer Cap Filing eliminated the Section I.2.2. definition “Energy Offer Cap” and consolidated tariff language related to the offer cap and floor in a single section.²⁸ However, because the subsequent Price Responsive Demand Filing became effective prior to the effective date of the Offer Cap Filing, the Price Responsive Demand Filing included two Tariff provisions related to Demand Response Resources that were not updated to include the Offer Cap Filing revisions. The instant filing remedies that. Specifically, Demand Reduction Offers are being added to the consolidated offer floor provisions of Section III.1.9.1.2 as follows:

(c) Supply Offers and Demand Reduction Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

In addition, the term “Energy Offer Cap” is being removed from Section III.1.10.1A(e)(ii), which will now stipulate that Demand Reduction Offers:

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.

IV. STAKEHOLDER PROCESS

The revisions filed herein were considered through the complete NEPOOL Participant Processes. At its May 12, 2020 meeting, the NEPOOL Markets Committee considered and voted unanimously to recommend that the NEPOOL Participants Committee support the revisions filed here.²⁹ Subsequent to the Markets Committee’s consideration, the NEPOOL Participants Committee unanimously approved the revisions filed herein as part of the Consent Agenda for its June 4, 2020 meeting.³⁰

²⁷ See *ISO New England Inc. and New England Power Pool, Revisions to Implement Full Integration of Demand Response*, Docket No. ER17-2164 (filed July 27, 2017) (“Price Responsive Demand Filing”).

²⁸ See Offer Cap Filing at 57 (eliminating the definition “Energy Offer Cap is \$1,000/MWh”). The Offer Cap Filing consolidated offer cap and floor provisions into Section III.19.12, including a Section III.1.9.1.2(a) providing that “the incremental energy value of an offer is capped at \$2,000/MWh.” Section III.1.9.1.2(a) applies to Demand Response Resources and is unchanged by the instant filing.

²⁹ During the Markets Committee vote, one abstention was recorded from a member in NEPOOL’s End User Sector.

³⁰ The Consent Agenda for a Participants Committee meeting, similar to the Consent Agenda for a Commission open meeting, is a group of actions (each recommended by a Technical Committee or subgroup established by the Participants Committee) to be taken by the Participants Committee through approval of a single motion at a meeting. All recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. In this case, the Participants Committee’s unanimous approval of the Consent Agenda (with one abstention recorded from Mr. Michael Kuser) included its support for the market rule changes filed herein.

V. 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.³¹ Notwithstanding its request for waiver, the Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations:

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

- This transmittal letter;
- Testimony of Dennis Robinson, sponsored solely by the ISO;
- Redlined Tariff sections effective September 30, 2020;
- Clean Tariff sections effective September 30, 2020; 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) – The ISO requests that the Tariff revisions filed herewith become effective on September 30, 2020, to apply to the Day-Ahead Energy Market offer and bid submission window that takes place on September 30, 2020 for the Operating Day of October 1, 2020.

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

³¹ 18 C.F.R. § 35.13 (2018).

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 this Part V of this transmittal letter.

35.13(b)(5) – The reasons for this filing are discussed in Part III 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 unanimous support of the NEPOOL 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.

VI. CONCLUSION

For the reasons set forth above, the Filing Parties respectfully request that the Commission accept the revisions filed here without condition or delay, to become effective on September 30, 2020.

Respectfully submitted,

ISO NEW ENGLAND INC.

By: /s/ Jennifer Wolfson

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**NEW ENGLAND POWER POOL
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**UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**ISO New England Inc. and
New England Power Pool**

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Docket No. ER20-____-000

**PREPARED TESTIMONY OF DENNIS ROBINSON
ON BEHALF OF ISO NEW ENGLAND INC.**

I. WITNESS IDENTIFICATION

Q: Please state your name, title, and business address.

A: My name is Dennis Robinson. I am the Director of Market & Resource Administration in the System Operations Department at ISO New England Inc. (the “ISO”). My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: Please describe your professional experience and educational background.

A: As Director of Market & Resource Administration, I am responsible for the day-to-day operations of New England’s wholesale energy markets, including the Day-Ahead Energy Market. I joined the ISO’s predecessor, the New England Power Pool, in 1991. Prior to becoming the ISO’s Director of Market & Resource Administration in March of 2012, I served as the ISO’s Manager of Hourly Markets. I hold a Bachelor of Science degree in Electrical Engineering from Western New England College.

15 **II. INCREASING THE WINDOW IN WHICH PARTICIPANTS MAY SUBMIT**
16 **OFFERS IN THE DAY-AHEAD ENERGY MARKET**

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

18 A: My testimony describes the primary change being made with this filing, that is, extending
19 the Day-Ahead Energy Market offer window so that it closes thirty minutes later in the
20 morning. As a result, the submission deadline for Market Participants to submit offers or
21 bids in the day-ahead market will be shifted from its current close at 10:00 a.m. to a new
22 close of 10:30 a.m. The ISO is moving the submission deadline later in the morning at the
23 request of Participants, who say the change will afford some suppliers additional time to
24 consider late-breaking information before finalizing their day-ahead offers and bids.

25
26 **Q: Please describe the current Day-Ahead Energy Market schedule.**

27 A: The ISO's current Day-Ahead Energy Market timeline was established in May of 2013,
28 when it was revised to better accommodate the fuel procurement activities of gas-fired
29 generators. Under this timeline, the existing tariff requires that Market Participants
30 submit offers and bids in the Day-Ahead Energy Market by 10:00 a.m., and further
31 requires that the ISO post the day-ahead market results by 1:30 p.m. In 2013, when this
32 schedule was established, the ISO committed to continue to evaluate further
33 improvements to the day-ahead clearing time. If the ISO was able to improve (that is,
34 decrease) the time required to clear the market, Participants could be permitted to submit
35 offers and bids in the day-ahead market later in the day.

Q: Why might some Market Participants benefit from the ability to submit offers and bids later in the day?

A: Suppliers have requested that the current Day-Ahead Energy Market submission deadline be extended in order to provide additional time to consider certain late-breaking information prior to finalizing their day-ahead offers and bids. For example, Participants submitting offers from gas-fired generators have said a later submission deadline would allow them to benefit from additional transparency, price discovery, and competition in the natural gas commodity market when formulating their ISO-NE day-ahead energy bids. Similarly, Participants who transact on the New York-New England interface have reported to the ISO-NE that they would find it beneficial to be able to consider the New York ISO (“NYISO”) day-ahead results when formulating their ISO-NE day-ahead offers.

Q: Please describe the ISO analysis that supports this change.

A: Since the May 2013 changes to the day-ahead timeline referenced above, process and technical improvements have enabled the ISO to decrease the time required to clear, validate, and post the day-ahead market results. For example, while the tariff requires that the ISO post the day-ahead results no later than 1:30 p.m. (three and-a-half hours after the close of the offer and bid submission window), the ISO is typically able to post the day-ahead results earlier, usually between 12:00 p.m. and 1:00 p.m. In fact, since the May 2013 implementation of the current schedule, the ISO has posted day-ahead results within three hours in 93% of days, and since the start of 2019, the percentage of days in which the ISO has posted day-ahead results within three hours has increased to 99.1%.

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61 **Q: Other than the deadline for submitting offers and bids, are any other changes being**
62 **made to the day-ahead timeline?**

63 A: No. The sole purpose of this change is to provide Market Participants with additional
64 time to submit Day-Ahead Energy Market offers and bids while preserving adequate time
65 for the ISO to clear, validate, and post the day-market results. Other than the shifting the
66 current 10:00 am offer and bid deadline forward by 30 minutes, no changes are being
67 made to the day-ahead timeline; nor are any changes being made to the re-offer period or
68 other real-time market activities that occur subsequent to the submission of offers and
69 bids in the day-ahead market.

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

72 A: Yes.

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

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77 Executed on July 27, 2020

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80 Dennis Robinson,

81 Director, Market & Resource Administration, ISO New England System Operations Department

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied 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, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as “Section III.1.4 Transactions,” and individually as a “Section III.1.4 Transaction.” Transactions that conform to the standards are referred to collectively as “Section III.1.4 Conforming Transactions,” and individually as a “Section III.1.4 Conforming Transaction.”

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

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

- (i) is not cleared or settled by the ISO as Counterparty;
- (ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

- (iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and
 - (iv) is not contingent on either party to carry out the Section III.1.4 Transaction.
- (b) In addition, to qualify as a Section III.1.4 Conforming Transaction:
- (i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;
 - (ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and
 - (iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.
- (c) As further requirements:
- (i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and
 - (ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

- (a) The following types of Claimed Capability Audits may be performed:
 - (i) An Establish Claimed Capability Audit establishes the Generator Asset's ability to respond to ISO Dispatch Instructions and to maintain performance at a specified output level for a specified duration.
 - (ii) A Seasonal Claimed Capability Audit determines a Generator Asset's capability to perform under specified summer and winter conditions for a specified duration.

- (iii) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.
- (iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR Audit value.
- (b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.
- (c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.
- (d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.
- (e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

- (a) An Establish Claimed Capability Audit may be performed only by a Generator Asset.
- (b) The time and date of an Establish Claimed Capability Audit shall be unannounced.
- (c) For a newly commercial Generator Asset:
 - (i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:
 - 1. Non-intermittent daily cycle hydro;
 - 2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
 - 3. Intermittent Generator Assets
 - (ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
 - (iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.
- (d) For Generator Assets with an Establish Claimed Capability Audit value:

- (i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.
- (ii) An Establish Claimed Capability Audit shall be performed within five Business Days of the date of the request.
- (iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
- (iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (e) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.
- (f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.
- (g) To conduct an Establish Claimed Capability Audit, the ISO shall:
 - (i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.
 - (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.
- (h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4

Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage)	2
Hydraulic Turbine – Other	
Hydro-Conventional Daily Pondage	2
Hydro-Conventional Run of River	
Hydro-Conventional Weekly	
Wind	2
Photovoltaic	
Fuel Cell	
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

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

III.1.5.1.3. Seasonal Claimed Capability Audits.

- (a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.
- (b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:
- (i) Non-intermittent daily hydro; and
 - (ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).
- (c) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's Seasonal Claimed Capability Audit obligation.
- (d) Except as provided in Section III.1.5.1.3(n) below, a summer Seasonal Claimed Capability Audit must be conducted:
- (i) At least once every Capability Demonstration Year;
 - (ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.
- (e) A winter Seasonal Claimed Capability Audit must be conducted:

- (i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:
 - (1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.
 - (2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.
 - (ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.
- (f) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:
- (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.
 - (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.
- (g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
- (h) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.
- (i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2

Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible (Electric Storage)	2
Hydraulic Turbine-Other	
Hydro-Conventional Weekly	2
Fuel Cell	1
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

- (k) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:
- (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;
 - (ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and
 - (iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.
- (l) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:
- (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;
 - (ii) Retain the current Seasonal Claimed Capability Audit value for the season; and
 - (iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.
- (m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal

Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

- (n) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:
 - (i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(f).
 - (ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.
 - (iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.
 - (iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(d)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.
 - (v) This Section III.1.5.1.3(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.
- (o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.3(j).

III.1.5.1.3.1 Seasonal DR Audits.

- (a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

- (b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.
- (c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:
 - (i) At least once every Capability Demonstration Year;
 - (ii) During the months of April through November;
- (d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:
 - (i) At least once every Capability Demonstration Year;
 - (ii) During the months of December through March.
- (e) A Seasonal DR Audit may be performed either:
 - (i) At the request of a Market Participant as described in subsection (f) below; or
 - (ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.
- (f) If a Market Participant requests a Seasonal DR Audit:
 - (i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.
 - (ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.
 - (iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
 - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:
 - (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.
 - (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.
 - (iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.
 - (iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

- (h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.
- (i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.
- (j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.
- (k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.
- (l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.
- (m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.
- (n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.
- (o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

- (a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.
- (b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:

- (i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.
- (ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.
- (c) If for a Generator Asset a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.
- (d) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:
 - (i) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.
 - (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iii) For Generator Assets, begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.
 - (iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
- (f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit	
Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4

Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage)	2
Hydraulic Turbine – Other	
Hydro-Conventional Daily Pondage	2
Hydro-Conventional Run of River	
Hydro-Conventional Weekly	
Wind	2
Photovoltaic	
Fuel Cell	
Other Electric Storage (Excludes Hydraulic Turbine – Reversible)	2
Demand Response Resource	1

- (g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource type not listed in Section III.1.5.1.4(f).

III.1.5.2 ISO-Initiated Parameter Auditing.

- (a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide 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 in accordance with Section III.9.5.
 - (vi) **CLAIM30.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
 - (vii) **Automatic Response Rate.** The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.
 - (viii) **Dual Fuel Capability.** A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).
- (c) Demand Response Resource audits shall be performed using the following methods:
- (i) **Maximum Reduction.** The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.
 - (ii) **Demand Response Resource Ramp Rate.** The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.
 - (iii) **Demand Response Resource Start-Up Time.** The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.
 - (iv) **Demand Response Resource Notification Time.** The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.
 - (v) **CLAIM10.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.
 - (vi) **CLAIM30.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
- (d) To conduct an audit based upon historical data, the ISO shall:
- (i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or
 - (ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.

- (e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.
- (f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:
 - (i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.
 - (ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.
- (g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.
- (h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:
 - (i) The Market Participant may submit a restoration plan to the ISO to restore that parameter.

The restoration plan shall:

 1. Provide an explanation of the discrepancy;
 2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
 3. Indicate the timeline for completing the restoration; and
 4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.
 - (ii) The ISO shall:
 1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
 2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
 3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

- (a) Two types of Reactive Capability Audits may be performed:
 - (i) A lagging Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to provide reactive power to the transmission system at a specified real power output or consumption.
 - (ii) A leading Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to absorb reactive power from the transmission system at a specified real power output or consumption.
- (b) The ISO shall develop a list of Reactive Resources that must conduct Reactive Capability Audits. The list shall include Reactive Resources that: (i) have a gross individual nameplate rating greater than 20 MVA; (ii) are directly connected, or are connected through equipment designed primarily for delivering real or reactive power to an interconnection point, to the transmission system at a voltage of 100 kV or above; and (iii) are not exempted from providing voltage control by the ISO. Additional criteria to be used in adding a Reactive Resource to the list includes, but is not limited to, the effect of the Reactive Resource on System Operating Limits, Interconnection Reliability Operating Limits, and local area voltage limits during the following operating states: normal, emergency, and system restoration.
- (c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall perform both a lagging Reactive Capability Audit and a leading Reactive Capability Audit.
- (d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.
- (e) The Reactive Capability Audit value of a Reactive Resource shall reflect any limitations based upon the interdependence of common elements between two or more Reactive Resources such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.
- (f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.
- (g) Reactive Capability Audits shall be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Reactive Resource to conduct Reactive Capability Audits more often than every five years if:
 - (i) there is a change in the Reactive Resource that may affect the reactive power capability of the Reactive Resource;
 - (ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Reactive Resource; or

- (iii) historical data shows that the amount of reactive power that the Reactive Resource can provide to or absorb from the transmission system is higher or lower than the latest audit data.
- (h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

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

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

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

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

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

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

requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 Transmission Constraint Penalty Factors.

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is \$10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is \$30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any transmission constraint is \$30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

III.1.7.6 Scheduling and Dispatching.

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

(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.

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

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

- (a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.
- (b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.
- (c) The Seasonal Claimed Capability of a Generator Asset is:
 - (i) Based upon review of historical data for non-intermittent daily cycle hydro.
 - (ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.
 - (iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:
 - a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.

- b. For a Generator Asset that is off-line and not available for commitment shall be zero.
- c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.
- (iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

III.1.7.12 Seasonal DR Audit Value of an Active Demand Capacity Resource.

- (a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.
- (b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Ramping.

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand

reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19 Real-Time Reserve Designation.

The ISO shall determine the Real-Time Reserve Designation for each eligible Resource in accordance with this Section III.1.7.19. The Real-Time Reserve Designation shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve.

III.1.7.19.1 Eligibility.

To be eligible to receive a Real-Time Reserve Designation, a Resource must meet all of the criteria enumerated in this Section III.1.7.19.1. A Resource that does not meet all of these criteria is not eligible to provide Operating Reserve and will not receive a Real-Time Reserve Designation.

- (1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.
- (2) The Resource must not be part of the first contingency supply loss.
- (3) The Resource must not be designated as constrained by transmission limitations.
- (4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)
- (5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19.2 Calculation of Real-Time Reserve Designation.

III.1.7.19.2.1 Generator Assets.

III.1.7.19.2.1.1 On-line Generator Assets.

The Manual Response Rate used in calculations in this section shall be the lesser of the Generator Asset's offered Manual Response Rate and its audited Manual Response Rate as described in Section III.1.5.2.

- (a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Non-Spinning Reserve shall be zero. For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit).
- (c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

III.1.7.19.2.1.2 Off-line Generator Assets.

For an off-line Generator Asset that is not a Fast Start Generator, all components of the Real-Time Reserve Designation shall be zero.

- (a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.

- (b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).
- (c) **Thirty-Minute Operating Reserve.** For an off-line Fast Start Generator, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Fast Start Generator's Offered CLAIM30, its CLAIM30, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Thirty-Minute Operating Reserve shall be zero, except during the last thirty minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Thirty-Minute Operating Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires), minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Fast Start Generator pursuant to subsection (b) above.

III.1.7.19.2.2 Dispatchable Asset Related Demand.

III.1.7.19.2.2.1 Storage DARDs.

- (a) **Ten-Minute Spinning Reserve.** For a Storage DARD, Ten-Minute Spinning Reserve shall be calculated as the absolute value of the amount of current telemetered consumption.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.
- (c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

III.1.7.19.2.2.2 Dispatchable Asset Related Demand Other Than Storage DARDs.

- (a) **Ten-Minute Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit). For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit).
- (c) **Thirty-Minute Operating Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (a) above. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Non-Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (b) above.

III.1.7.19.2.3 Demand Response Resources.

For a Demand Response Resource that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall

be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2.

III.1.7.19.2.3.1 Dispatched.

- (a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction). For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction).
- (c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within thirty minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction) minus the Ten-Minute Spinning Reserve quantity calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

III.1.7.19.2.3.2 Non-Dispatched.

For a Demand Response Resource that is not being dispatched that is not a Fast Start Demand Response Resource, all components of the Real-Time Reserve Designation shall be zero.

- (a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Demand Response Resource's Offered CLAIM10, its CLAIM10, and its Maximum Reduction.
- (c) **Thirty-Minute Operating Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Demand Response Resource's Offered CLAIM30, its CLAIM30, and its Maximum Reduction, minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Demand Response Resource pursuant to subsection (b) above.

III.1.7.20 Information and Operating Requirements.

- (a) [Reserved.]
- (b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO Resources that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output, consumption, or demand reduction levels of Generator Assets, DARDs, or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.
- (c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.
- (d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction

purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market.

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

III.1.8 [Reserved.]

III.1.9 Pre-scheduling.

III.1.9.1 Offer and Bid Caps and Cost Verification for Offers and Bids.

III.1.9.1.1 Cost Verification of Resource Offers.

The incremental energy values of Supply Offers and Demand Response Resources above \$1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or \$1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than \$1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to \$1,000/MWh, then the adjusted offer for the Resource is set at \$1,000/MWh;

(ii) If the Reference Level value is greater than \$1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

III.1.9.1.2 Offer and Bid Caps.

(a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at \$2,000/MWh.

(b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.

(c) Supply Offers [and Demand Reduction Offers](#) shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

(d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.

(e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

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

III.1.9.8 [Reserved.]

III.1.10

Scheduling.

III.1.10.1

General.

(a) The ISO shall administer scheduling processes to implement 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 Generator Assets or Demand Response Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers or Demand Reduction Offers.

III.1.10.1A Energy Market Scheduling.

Market Participants may submit offers and bids in the Day-Ahead Energy Market until
~~offers and bids shall occur not later than~~ 10:00-30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

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

(b) **External Transactions** – All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the

price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

- (i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;
 - (ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;
 - (iii) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;
 - (iv) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction Cap;
 - (v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.
- (c) **Generator Asset Supply Offers** – Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

- (i) Shall specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;
 - (ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;
 - (iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual-fuel Generator Assets in Section III.A.3 of Appendix A;
 - (iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;
 - (v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource (except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and
 - (vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.
- (d) **DARD Demand Bids** – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including to the Maximum Consumption Limit and Minimum Consumption Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

(iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers** – Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is ~~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:

$$DRTP = P_{th}X - \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction Offer, or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

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

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

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

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

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy supply or consumption 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 facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

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

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource shall not be Self-Scheduled.

III.1.10.4 External Resources.

Market Participants with External Resources may submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

III.1.10.5 Dispatchable Asset Related Demand.

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

- (i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;
- (ii) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;
- (iii) abide by the ISO maintenance coordination procedures; and
- (iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

III.1.10.6 Electric Storage

A storage facility is a facility that is capable of receiving electricity from the grid and storing the energy for later injection of electricity back to the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

- (i) comprise one or more storage facilities at the same point of interconnection;
- (ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;
- (iii) be directly metered;
- (iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;
- (v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;
- (vi) settle its injection of electricity to the grid as a Generator Asset and its receipt of electricity from the grid as a DARD;
- (vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and
- (viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:

- (i) satisfy the requirements applicable to an Electric Storage Facility; and
- (ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and
- (iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.

(c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

- (i) satisfy the requirements applicable to an Electric Storage Facility;
- (ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;
- (iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;
- (iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;
- (v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;
- (vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;
- (vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and
- (viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).

(d) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:

- (i) A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.
 - (ii) A storage facility's charging load shall not qualify as a DARD if the Host Participant is unwilling or unable to support the registration, metering, and accounting of the storage facility's load as a separate and distinct Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging load.
 - (iii) The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.
 - (iv) Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.
 - (v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.
- (e) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.
- (f) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.
- (g) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered

and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

- (h) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.
- (i) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

III.1.10.7 External Transactions.

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

- (a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.
- (b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.
- (c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.
- (d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.
- (e) [Reserved.]

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

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone 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 Transaction Scheduling.

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

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

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

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

costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

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

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, permit the transaction to be scheduled.

III.1.10.8 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 Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

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

Transaction re-offer provisions of this Section III.1.10.9(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

- (i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual-fuel Generator Assets), and the quantity and price pairs of its Blocks may be modified.
- (ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

(e) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit. A Market Participant may not request to Self-Schedule a Demand Response Resource. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

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

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

request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

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

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

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

III.1.11 Dispatch.

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

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the

Market Participants and the operation of the New England Control Area; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

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

III.1.11.3 Dispatchable Resources.

With the exception of Settlement Only Resources, Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, nuclear-powered Resources and photovoltaic Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

- (a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.
- (b) The ISO shall implement the dispatch of energy from Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.
- (c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.
- (d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.
- (e) Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind and hydro Intermittent Power Resources that are not Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

- (i) A 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-fuel Generator Assets that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fuel Generator Assets that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fuel Generator Assets that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

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

III.1.11.5 Dispatchability Requirements for Intermittent Power Resources.

- (a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.
- (b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. 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.

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied 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, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as “Section III.1.4 Transactions,” and individually as a “Section III.1.4 Transaction.” Transactions that conform to the standards are referred to collectively as “Section III.1.4 Conforming Transactions,” and individually as a “Section III.1.4 Conforming Transaction.”

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

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

- (i) is not cleared or settled by the ISO as Counterparty;
- (ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

- (iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and
 - (iv) is not contingent on either party to carry out the Section III.1.4 Transaction.
- (b) In addition, to qualify as a Section III.1.4 Conforming Transaction:
- (i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;
 - (ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and
 - (iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.
- (c) As further requirements:
- (i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and
 - (ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

- (a) The following types of Claimed Capability Audits may be performed:
 - (i) An Establish Claimed Capability Audit establishes the Generator Asset's ability to respond to ISO Dispatch Instructions and to maintain performance at a specified output level for a specified duration.
 - (ii) A Seasonal Claimed Capability Audit determines a Generator Asset's capability to perform under specified summer and winter conditions for a specified duration.

- (iii) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.
- (iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR Audit value.
- (b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.
- (c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.
- (d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.
- (e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

- (a) An Establish Claimed Capability Audit may be performed only by a Generator Asset.
- (b) The time and date of an Establish Claimed Capability Audit shall be unannounced.
- (c) For a newly commercial Generator Asset:
 - (i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:
 - 1. Non-intermittent daily cycle hydro;
 - 2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
 - 3. Intermittent Generator Assets
 - (ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
 - (iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.
- (d) For Generator Assets with an Establish Claimed Capability Audit value:

- (i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.
- (ii) An Establish Claimed Capability Audit shall be performed within five Business Days of the date of the request.
- (iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
- (iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (e) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.
- (f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.
- (g) To conduct an Establish Claimed Capability Audit, the ISO shall:
 - (i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.
 - (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.
- (h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4

Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

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

III.1.5.1.3. Seasonal Claimed Capability Audits.

- (a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.
- (b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:
- (i) Non-intermittent daily hydro; and
 - (ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).
- (c) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's Seasonal Claimed Capability Audit obligation.
- (d) Except as provided in Section III.1.5.1.3(n) below, a summer Seasonal Claimed Capability Audit must be conducted:
- (i) At least once every Capability Demonstration Year;
 - (ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.
- (e) A winter Seasonal Claimed Capability Audit must be conducted:

- (i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:
 - (1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.
 - (2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.
 - (ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.
- (f) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:
- (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.
 - (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.
- (g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
- (h) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.
- (i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2

Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible (Electric Storage)	2
Hydraulic Turbine-Other	
Hydro-Conventional Weekly	2
Fuel Cell	1
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

- (k) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:
- (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;
 - (ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and
 - (iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.
- (l) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:
- (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;
 - (ii) Retain the current Seasonal Claimed Capability Audit value for the season; and
 - (iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.
- (m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal

Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

- (n) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:
 - (i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(f).
 - (ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.
 - (iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.
 - (iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(d)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.
 - (v) This Section III.1.5.1.3(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.
- (o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.3(j).

III.1.5.1.3.1 Seasonal DR Audits.

- (a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

- (b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.
- (c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:
 - (i) At least once every Capability Demonstration Year;
 - (ii) During the months of April through November;
- (d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:
 - (i) At least once every Capability Demonstration Year;
 - (ii) During the months of December through March.
- (e) A Seasonal DR Audit may be performed either:
 - (i) At the request of a Market Participant as described in subsection (f) below; or
 - (ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.
- (f) If a Market Participant requests a Seasonal DR Audit:
 - (i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.
 - (ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.
 - (iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
 - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:
 - (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.
 - (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.
 - (iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.
 - (iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

- (h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.
- (i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.
- (j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.
- (k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.
- (l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.
- (m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.
- (n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.
- (o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

- (a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.
- (b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:

- (i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.
- (ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.
- (c) If for a Generator Asset a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.
- (d) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:
 - (i) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.
 - (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iii) For Generator Assets, begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.
 - (iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
- (f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit	
Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4

Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage)	2
Hydraulic Turbine – Other	
Hydro-Conventional Daily Pondage	2
Hydro-Conventional Run of River	
Hydro-Conventional Weekly	
Wind	2
Photovoltaic	
Fuel Cell	
Other Electric Storage (Excludes Hydraulic Turbine – Reversible)	2
Demand Response Resource	1

- (g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource type not listed in Section III.1.5.1.4(f).

III.1.5.2 ISO-Initiated Parameter Auditing.

- (a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide 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 in accordance with Section III.9.5.
 - (vi) **CLAIM30.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
 - (vii) **Automatic Response Rate.** The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.
 - (viii) **Dual Fuel Capability.** A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).
- (c) Demand Response Resource audits shall be performed using the following methods:
- (i) **Maximum Reduction.** The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.
 - (ii) **Demand Response Resource Ramp Rate.** The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.
 - (iii) **Demand Response Resource Start-Up Time.** The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.
 - (iv) **Demand Response Resource Notification Time.** The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.
 - (v) **CLAIM10.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.
 - (vi) **CLAIM30.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
- (d) To conduct an audit based upon historical data, the ISO shall:
- (i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or
 - (ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.

- (e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.
- (f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:
 - (i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.
 - (ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.
- (g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.
- (h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:
 - (i) The Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:
 1. Provide an explanation of the discrepancy;
 2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
 3. Indicate the timeline for completing the restoration; and
 4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.
 - (ii) The ISO shall:
 1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
 2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
 3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

- (a) Two types of Reactive Capability Audits may be performed:
 - (i) A lagging Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to provide reactive power to the transmission system at a specified real power output or consumption.
 - (ii) A leading Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to absorb reactive power from the transmission system at a specified real power output or consumption.
- (b) The ISO shall develop a list of Reactive Resources that must conduct Reactive Capability Audits. The list shall include Reactive Resources that: (i) have a gross individual nameplate rating greater than 20 MVA; (ii) are directly connected, or are connected through equipment designed primarily for delivering real or reactive power to an interconnection point, to the transmission system at a voltage of 100 kV or above; and (iii) are not exempted from providing voltage control by the ISO. Additional criteria to be used in adding a Reactive Resource to the list includes, but is not limited to, the effect of the Reactive Resource on System Operating Limits, Interconnection Reliability Operating Limits, and local area voltage limits during the following operating states: normal, emergency, and system restoration.
- (c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall perform both a lagging Reactive Capability Audit and a leading Reactive Capability Audit.
- (d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.
- (e) The Reactive Capability Audit value of a Reactive Resource shall reflect any limitations based upon the interdependence of common elements between two or more Reactive Resources such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.
- (f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.
- (g) Reactive Capability Audits shall be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Reactive Resource to conduct Reactive Capability Audits more often than every five years if:
 - (i) there is a change in the Reactive Resource that may affect the reactive power capability of the Reactive Resource;
 - (ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Reactive Resource; or

- (iii) historical data shows that the amount of reactive power that the Reactive Resource can provide to or absorb from the transmission system is higher or lower than the latest audit data.
- (h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

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

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

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

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

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

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

requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 Transmission Constraint Penalty Factors.

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is \$10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is \$30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any transmission constraint is \$30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

III.1.7.6 Scheduling and Dispatching.

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

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

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

- (a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.
- (b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.
- (c) The Seasonal Claimed Capability of a Generator Asset is:
 - (i) Based upon review of historical data for non-intermittent daily cycle hydro.
 - (ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.
 - (iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:
 - a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.

- b. For a Generator Asset that is off-line and not available for commitment shall be zero.
- c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.
- (iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

III.1.7.12 Seasonal DR Audit Value of an Active Demand Capacity Resource.

- (a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.
- (b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Ramping.

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand

reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19 Real-Time Reserve Designation.

The ISO shall determine the Real-Time Reserve Designation for each eligible Resource in accordance with this Section III.1.7.19. The Real-Time Reserve Designation shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve.

III.1.7.19.1 Eligibility.

To be eligible to receive a Real-Time Reserve Designation, a Resource must meet all of the criteria enumerated in this Section III.1.7.19.1. A Resource that does not meet all of these criteria is not eligible to provide Operating Reserve and will not receive a Real-Time Reserve Designation.

- (1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.
- (2) The Resource must not be part of the first contingency supply loss.
- (3) The Resource must not be designated as constrained by transmission limitations.
- (4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)
- (5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19.2 Calculation of Real-Time Reserve Designation.

III.1.7.19.2.1 Generator Assets.

III.1.7.19.2.1.1 On-line Generator Assets.

The Manual Response Rate used in calculations in this section shall be the lesser of the Generator Asset's offered Manual Response Rate and its audited Manual Response Rate as described in Section III.1.5.2.

- (a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Non-Spinning Reserve shall be zero. For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit).
- (c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

III.1.7.19.2.1.2 Off-line Generator Assets.

For an off-line Generator Asset that is not a Fast Start Generator, all components of the Real-Time Reserve Designation shall be zero.

- (a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.

- (b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).
- (c) **Thirty-Minute Operating Reserve.** For an off-line Fast Start Generator, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Fast Start Generator's Offered CLAIM30, its CLAIM30, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Thirty-Minute Operating Reserve shall be zero, except during the last thirty minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Thirty-Minute Operating Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires), minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Fast Start Generator pursuant to subsection (b) above.

III.1.7.19.2.2 Dispatchable Asset Related Demand.

III.1.7.19.2.2.1 Storage DARDs.

- (a) **Ten-Minute Spinning Reserve.** For a Storage DARD, Ten-Minute Spinning Reserve shall be calculated as the absolute value of the amount of current telemetered consumption.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.
- (c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

III.1.7.19.2.2.2 Dispatchable Asset Related Demand Other Than Storage DARDs.

- (a) **Ten-Minute Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit). For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit).
- (c) **Thirty-Minute Operating Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (a) above. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Non-Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (b) above.

III.1.7.19.2.3 Demand Response Resources.

For a Demand Response Resource that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall

be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2.

III.1.7.19.2.3.1 Dispatched.

- (a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction). For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction).
- (c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within thirty minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction) minus the Ten-Minute Spinning Reserve quantity calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

III.1.7.19.2.3.2 Non-Dispatched.

For a Demand Response Resource that is not being dispatched that is not a Fast Start Demand Response Resource, all components of the Real-Time Reserve Designation shall be zero.

- (a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Demand Response Resource's Offered CLAIM10, its CLAIM10, and its Maximum Reduction.
- (c) **Thirty-Minute Operating Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Demand Response Resource's Offered CLAIM30, its CLAIM30, and its Maximum Reduction, minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Demand Response Resource pursuant to subsection (b) above.

III.1.7.20 Information and Operating Requirements.

- (a) [Reserved.]
- (b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO Resources that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output, consumption, or demand reduction levels of Generator Assets, DARDs, or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.
- (c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.
- (d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction

purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market.

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

III.1.8 [Reserved.]

III.1.9 Pre-scheduling.

III.1.9.1 Offer and Bid Caps and Cost Verification for Offers and Bids.

III.1.9.1.1 Cost Verification of Resource Offers.

The incremental energy values of Supply Offers and Demand Response Resources above \$1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or \$1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than \$1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to \$1,000/MWh, then the adjusted offer for the Resource is set at \$1,000/MWh;

(ii) If the Reference Level value is greater than \$1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

III.1.9.1.2 Offer and Bid Caps.

(a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at \$2,000/MWh.

(b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.

(c) Supply Offers and Demand Reduction Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

(d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.

(e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

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

III.1.9.8 [Reserved.]

III.1.10

Scheduling.

III.1.10.1

General.

(a) The ISO shall administer scheduling processes to implement 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 Generator Assets or Demand Response Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers or Demand Reduction Offers.

III.1.10.1A Energy Market Scheduling.

Market Participants may submit offers and bids in the Day-Ahead Energy Market until 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

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

(b) **External Transactions** – All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and

sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

- (i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;
 - (ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;
 - (iii) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;
 - (iv) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction Cap;
 - (v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.
- (c) **Generator Asset Supply Offers** – Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

- (i) Shall specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;
 - (ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;
 - (iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual-fuel Generator Assets in Section III.A.3 of Appendix A;
 - (iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;
 - (v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource (except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and
 - (vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.
- (d) DARD Demand Bids** – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including to the Maximum Consumption Limit and Minimum Consumption Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

(iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers** – Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.

(f) **Demand Reduction Threshold Price** – The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

(a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.

(c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

- (d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.
- (e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$D RTP = P_{th} X \frac{FPI_c}{FPI_h}$$

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 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-ratio 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.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy supply or consumption 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 facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

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

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource shall not be Self-Scheduled.

III.1.10.4 External Resources.

Market Participants with External Resources may submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

III.1.10.5 Dispatchable Asset Related Demand.

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

- (i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;
- (ii) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;
- (iii) abide by the ISO maintenance coordination procedures; and
- (iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

III.1.10.6 Electric Storage

A storage facility is a facility that is capable of receiving electricity from the grid and storing the energy for later injection of electricity back to the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

- (i) comprise one or more storage facilities at the same point of interconnection;
- (ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;
- (iii) be directly metered;
- (iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;
- (v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;
- (vi) settle its injection of electricity to the grid as a Generator Asset and its receipt of electricity from the grid as a DARD;
- (vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and
- (viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:

- (i) satisfy the requirements applicable to an Electric Storage Facility; and
- (ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and
- (iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.

(c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

- (i) satisfy the requirements applicable to an Electric Storage Facility;
- (ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;
- (iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;
- (iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;
- (v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;
- (vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;
- (vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and
- (viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).

(d) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:

- (i) A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.
 - (ii) A storage facility's charging load shall not qualify as a DARD if the Host Participant is unwilling or unable to support the registration, metering, and accounting of the storage facility's load as a separate and distinct Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging load.
 - (iii) The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.
 - (iv) Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.
 - (v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.
- (e) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.
- (f) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.
- (g) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered

and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

- (h) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.
- (i) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

III.1.10.7 External Transactions.

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

- (a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.
- (b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.
- (c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.
- (d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.
- (e) [Reserved.]

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

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone 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 Transaction Scheduling.

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

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

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

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

costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

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

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, permit the transaction to be scheduled.

III.1.10.8 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 Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

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

Transaction re-offer provisions of this Section III.1.10.9(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

- (i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual-fuel Generator Assets), and the quantity and price pairs of its Blocks may be modified.
- (ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

(e) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit. A Market Participant may not request to Self-Schedule a Demand Response Resource. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

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

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

request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

- (ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit at a specified value. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched at or above the requested amount for the hour in question.
- (g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.
- (h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.
- (i) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

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

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the

Market Participants and the operation of the New England Control Area; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

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

III.1.11.3 Dispatchable Resources.

With the exception of Settlement Only Resources, Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, nuclear-powered Resources and photovoltaic Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

- (a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.
- (b) The ISO shall implement the dispatch of energy from Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.
- (c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.
- (d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.
- (e) Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind and hydro Intermittent Power Resources that are not Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

- (i) A 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-fuel Generator Assets that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fuel Generator Assets that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fuel Generator Assets that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

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

III.1.11.5 Dispatchability Requirements for Intermittent Power Resources.

- (a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.
- (b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. 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.

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