SECTION III

MARKET RULE 1

STANDARD MARKET DESIGN

Table of Contents

Page

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction. This Market Rule 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. This Market Rule addresses each of the three time frames pertinent to the daily operation of the New England Markets: Pre-scheduling, Scheduling, and Dispatch. This Market Rule shall become effective on the Operations Date.

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.]

[Sheet Nos. 7014 - 7060 are reserved for future use.]

III.1.3.3 [Reserved.]

III.1.4 [Reserved.]

III.1.5 [Reserved.]

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 [Reserved.]

III.1.7.2 [Reserved.]

III.1.7.3 Agents. A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 [Reserved.]

III.1.7.6 Scheduling and Dispatching.

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

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

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

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

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

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

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

III.1.7.7 **Energy Pricing.** The price paid for energy bought and sold in the New England Markets will reflect the hourly Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices in an hour caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices in an hour, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule.

III.1.7.8 Market Participant Resources. A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the procedures specified in this Market Rule and the ISO New England Manuals.

III.1.7.9 Real-Time Reserve Prices. The price paid for the provision of Real-Time Operating Reserve in the New England Markets will reflect the integrated hourly Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.10 Other Transactions.

(a) Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the obligations of Market Participants to make ICAP Resources 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 and the ISO New England Manuals.

(b) [Reserved.]

(c) [Reserved.]

III.1.7.11 [Reserved.]

III.1.7.12 [Reserved.]

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve. The ISO shall schedule to the Operating Reserve and load-following requirements of the New England Control Area and the New England Markets in scheduling Resources pursuant to this Market Rule. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of this Market Rule. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Regulation.

(a) Regulation shall be supplied from generators located within the metered electrical boundaries of the New England Control Area. Market Participants offering Regulation shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall obtain and maintain an amount of Regulation equal to the New England Control Area Regulation objective as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) The Regulation range of a unit shall be at least twice the amount of Regulation assigned and no less than the minimum specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(d) A unit that is providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided. The amount of Regulation provided by a unit shall serve to redefine the Economic Minimum Limit and Economic Maximum Limit of that unit, in that the amount of Regulation shall be added to the unit's Economic Minimum Limit or automatic low limit while regulating, whichever is greater, and subtracted from its Economic Maximum Limit or automatic high limit, which ever is less. Qualified Regulation must satisfy the verification tests described in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19 **Ramping.** A generating unit dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the unit's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the ISO for that unit and shall be subject to sanctions for failure to comply as described in ***Appendix B*.**

III.1.7.19A Real-Time Reserve.

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

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

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

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: report to the ISO sources of energy available for operation; supply to the ISO all applicable Offer Data; report to the ISO units that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output levels of generating units, or change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating 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 the ICAP Resources they have provided that are available for pool operation; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

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

III.1.8 [Reserved.]

III.1.9 Pre-scheduling.

III.1.9.1 [Reserved.]

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities. Market Participants authorized and intending to request market-based Start-Up and No-Load Fees in their Offer Data shall submit a specification of such fees to the ISO for each generating unit as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline specified in the ISO New England Manuals and ISO New England Administrative Procedures and shall remain in effect without change throughout each such period for which a specification was submitted. The

ISO shall reject any request for Start-Up and No-Load Fees 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 be obligated to purchase or sell energy in the amount of the deviations at the applicable Real-Time Prices, unless otherwise specified by this Market Rule, 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 Cost Component and Loss Component price differences, unless otherwise specified by this Market Rule.

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

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of generating Resources with notification time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers for such units, as submitted in accordance with Section 1.10.1A(f), for such periods and the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and such Resources shall be treated as Pool-Scheduled Resources and shall be eligible to receive NCPC Credits under Section III.3.2.3 in accordance with the binding Supply Offers submitted.

III.1.10.1A Day-Ahead Energy Market Scheduling. The following actions shall occur not later than 12:00 noon 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.

(a) Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resource increments, including hydropower units, Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such

Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be equal to or greater than zero and shall not exceed the energy Supply Offer limitation specified in this Section.

(b) [Reserved.]

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

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

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

(iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to \$0.0/MWh; and

(iv) If the sum of all submitted fixed External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all fixed External Transaction sales at the applicable External Node shall be set equal to \$1,000/MWh.

(d) Market Participants wishing to sell into the New England Markets, from either internal Resources or External Resources, shall submit Supply Offers or External Transactions for the supply of energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Regulation, Operating Reserve or other services as applicable, for the following Operating Day. Supply Offers shall be submitted to the ISO in the form specified by the ISO and shall contain the information specified in the ISO's Offer Data specification, as applicable. External Transactions shall be submitted to the ISO according to Section III.1.10.7 of this Market Rule. 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. Market Participants owning or controlling the output of an ICAP Resource that has not been rendered unavailable by a

Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage or, in the case of a Dispatchable Asset Related Demand, by a condition that renders the Resource incapable of reducing consumption, shall submit Supply Offers or Demand Bids for the available capacity of such ICAP Resource, including any portion that is Self-Scheduled by the Market Participant claiming the Resource as an ICAP Resource. The submission of Supply Offers for Resources that are not ICAP Resources shall be optional, but any such Supply Offers must contain the information specified in the ISO's Offer Data specification, as applicable. Energy offered from generating Resources that are not ICAP Resources shall not be supplied from Resources that are included in or otherwise committed to supply the operating reserve requirements of another Control Area. The foregoing Supply Offers and Demand Bids for ICAP Resources, as applicable and non ICAP Resources:

(i) Shall specify the Resource and energy for each hour in the offer period;

(ii) Shall specify the amounts and prices for the entire Operating Day for each Resource offered by the Market Participant to the ISO;

(iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify Start-Up and No-Load Fees equal to the specification of such fees for such unit on file with the ISO (Market Participant changes to the Start-Up Fee and No-Load Fee can only occur during the open periodic bidding enrollment periods (daily));

(iv) Shall set forth any special conditions upon which the Market Participant proposes to supply a Resource increment;

(v) Shall specify a minimum run time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;

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

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

(viii) Shall be final as to the price or prices at which the Market Participant proposes to supply or consume energy or other services to the New England Markets, such price or prices for Resources or portions of Resources scheduled in the Day-Ahead Energy Market being guaranteed by the Market Participant for the period extending through the end of the following Operating Day or, in the case of a generating Pool-Scheduled Resource continuing to run into the second Operating Day to satisfy its minimum run time, such price or prices being guaranteed by the Market Participant for the period extending into the second Operating Day that satisfies the Resource's minimum run time; and

(ix) Shall not specify an energy offer or bid price below \$0/MWh or above \$1,000/MWh.

(e) A Market Participant that wishes to make a Resource available to sell Regulation service shall submit a Supply Offer for Regulation that shall specify the Automatic Response Rate in megawatts per minute, the price in dollars per MWh of the Regulation capability being offered, such Regulation capability as calculated by the ISO by multiplying the submitted Automatic Response Rate by five minutes, and such other information specified by the ISO as may be necessary to evaluate the Supply Offer and the generating Resource's Regulation Opportunity Costs. The price of the Supply Offer shall not exceed $100/MWh. Qualified Regulation capability must satisfy the verification tests specified in the ISO New England Manuals and ISO New England Administrative Procedures. Regulation capability amounts will be adjusted as necessary in the case where a generating unit's compliance rating is less than 90%. The audited Regulation capability will be deemed equal to the most recently calculated compliance rating times the 5-minute

Regulation capability quantities utilized in that compliance rating calculation, rounded to the nearest whole megawatt. The Resource's Automatic Response Rate will then be adjusted based upon the audited Regulation capability.

(f) Each Market Participant owning or controlling the output of an ICAP Resource shall submit a forecast of the availability of each such ICAP Resource for the next seven days. A Market Participant (i) may submit a non-binding forecast of the price at which it expects to offer a generating Resource increment to the ISO over the next seven days, and (ii) shall submit a binding Supply Offer for energy, along with Start-Up and No-Load Fees, if any and if applicable, for the next seven days, for any ICAP Resource with a minimum notification time greater than 24 hours.

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

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

(i) 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 to sell energy in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as generators committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide energy in the Real-Time dispatch unless the schedules for such units are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy and related services, Start-Up Fees, No-Load Fees, and the specified operating characteristics, offered by Market Participants to the ISO by the offer deadline specified in Section III.1.10.1A.

(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 of other Resources, the submitted Demand Bids and Decrement

Bids and Operating Reserve and Replacement Reserve requirements.

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

(d) The Market Participant seller whose Resource is selected as a Pool-Scheduled Resource shall receive payments or credits for energy or related services, or for Start-Up and No-Load Fees, from the ISO on behalf of the Market Participant buyers in accordance with Section III.3 of this Market Rule. Additionally, the Market Participant seller shall receive for Pool-Scheduled Resources scheduled in the Real-Time Energy Market that were not Scheduled in the Day-Ahead Energy Market, a pro-rata share of its applicable Start-Up Fee if the ISO cancels its selection of the Resource as a Pool-Scheduled Resource and so notifies the Market Participant seller before the Resource is synchronized ("Cancellation Fee").

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

(f) Eligibility for NCPC in the Day-Ahead Market under Section III.3.2.3 is affected by Resource Self-Schedules. The specific rules related to the impact of Resource Self-Schedules on eligibility for NCPC may be found in *Appendix F* of this Market Rule.

(g) Eligibility for NCPC in the Real-Time Market under Section III.3.2.3 is affected by Resource Self-Schedules. The specific rules related to the impact of Resource Self-Schedules on eligibility for NCPC may be found in *Appendix F* of this Market Rule.

(h) Eligibility for NCPC in the Real-Time Market under Section III.3.2.3 may be affected by Resource trips. The specific rules related to the impact of Resource trips on eligibility for NCPC may be found in ***Appendix F*** of this Market Rule.

(i) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 is affected by ramping up in response to a start-up instruction and ramping down in response to a shutdown instruction. The specific rules related to the ramping impacts on eligibility for NCPC may be found in ***Appendix F*** of this Market Rule.

III.1.10.3 Self-Scheduled Resources. Self-Scheduled Resources shall be governed by the following principles and procedures.

(a) [Reserved.]

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

(c) Market Participants shall make available their Self-Scheduled ICAP Resources, including increments available above Self-Scheduled increments, to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

Market Participants shall submit Supply Offers for non-ICAP Resources for the entire capability range of the Resource in excess of the portion of the Resource exported as non-recallable energy or otherwise Self-Scheduled in the Real-Time Energy Market.

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

III.1.10.4 ICAP Resources.

(a) An ICAP Resource selected as a Pool-Scheduled Resource shall be made available for scheduling and dispatch at the direction of the ISO. Any generating Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent such energy is not delivered except that a reduction in output or removal from service of a generating unit in response to changes in market conditions that is approved by the ISO shall not constitute a Generator Forced Outage. A Market Participant offering such a generating Resource 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.

(b) Energy from an ICAP Resource that has not been scheduled in the Day-Ahead Energy Market may be sold on a bilateral basis by the Market Participant, may be Self-Scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Market Rule. An ICAP Resource that has not been scheduled in the Day-Ahead Energy Market and that has been scheduled as an External Transaction sale must be made available upon request to the ISO for scheduling and dispatch during the Operating Day if the ISO declares an Emergency Condition. Any such Resource so scheduled and dispatched shall receive the applicable Real-Time Price for energy delivered.

III.1.10.5 External Resources.

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

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

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

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

III.1.10.6 [Reserved.]

III.1.10.7 External Transactions.

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

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

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

(d) A Market Participant submitting a priced External Transaction supporting an ICAP Import Contract or Capacity Supply Obligation to the Real-Time Energy Market must link the transaction to the associated NERC E-Tag and transmission reservation, if required, no later than one hour before the Operating Hour in order to be eligible for scheduling in the Real-Time Energy Market. All other External Transactions submitted to the Real-Time Energy Market must contain the associated NERC E-Tag and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market. Failure to provide the required information may cause the transaction not to be scheduled in the Real-Time Energy Market and may subject the Market Participant to applicable capacity market penalties as set forth in this Market Rule.

(i) For the Phase I/II HVDC-TF, the ability to link the reservation and E-Tag later than one hour before the Operating Hour is permissible only for priced capacity backed transactions associated with the HQ Interconnection Excess, if any. For other transactions on the Phase I/II HVDC-TF, a Market Participant must submit the reservation and E-Tag at the time of submission to the Real-Time Energy Market; failure to do so will cause the transaction not to be scheduled in the Real-Time Energy Market and may subject the Market Participant to applicable capacity market penalties as set forth in this Market Rule.

(e) All Real-Time External Transactions shall be scheduled and curtailed in accordance with the ISO New England Manuals and all applicable tariffs.

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

III.1.10.8 ISO Responsibilities.

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

England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(b) Not later than 4:00 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

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

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

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Pool-Scheduled Resources and to direct that schedules be changed in an Emergency, a Resource re-offer period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day or such other re-offer period as necessary to account for software failures or other events. During the re-offer period, Market Participants may submit revisions to generation Supply Offers and revisions to Demand Bids for any Dispatchable Asset Related Demand Resource. Resources scheduled subsequent to the closing of the re-offer period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) A Market Participant may adjust the schedule of a Resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the ISO is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect (or such shorter period, up to 20 minutes prior to the hour, when the ISO has notified the Market Participants that it has the necessary hardware, software, and procedures in place to implement the shorter notice period), as follows:

(i) A Market Participant may Self-Schedule any of its Resources consistent with the ISO New England Manuals and ISO New England Administrative Procedures;

(ii) [Reserved; or

(iii) [Reserved]; or

(iv) A Market Participant may remove from service a Resource increment, that it had previously designated as Self-Scheduled, provided that the ISO shall have the option to schedule energy from any such Self-Scheduled Resource increment that is an ICAP Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Fee.

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

(d) **[Reserved.]**

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

III.1.11 Dispatch. The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output. The ISO shall have the authority to direct any Market Participant to adjust the output of any Pool-Scheduled

Resource increment within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources, subject to an obligation to pay any applicable Start-Up, No-Load or Cancellation Fees. The ISO shall adjust the output of Pool-Scheduled Resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (c) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis. In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Pool-dispatched Resources.

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

Control Area and the availability of other Resources to the ISO.

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

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified. During each hour of any tests performed under Section III.1.11.3(c),(i), the Resources under test shall be considered Self-Scheduled Resources for the purposes of calculating NCPC Credits. Procedures related to the ISO's modification of operational related Offer Data and Market Participant requests for testing shall be as defined in the ISO New England Manuals.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to desired output levels as practical, consistent with Accepted Electric Industry Practice.

III.1.11.4 Emergency Condition. If the ISO anticipates or declares an Emergency Condition, all sales out of the New England Control Area from ICAP Resources may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 Regulation.

(a) A Market Participant may satisfy its Regulation obligation from its own Resources capable of performing Regulation service, by contractual arrangements with other Market Participants, or by purchases from the New England Markets at the rates set forth in Section III.3.2.2.

(b) The ISO shall obtain Regulation service from the least-cost alternatives available from either Pool-Scheduled or Self-Scheduled Resources as needed to meet New England Control Area requirements not otherwise satisfied by the Market Participants. The ISO assigns Regulation to eligible generating units using the ISO Regulation assessment software. The Regulation assessment software calculates, at five minutes after the hour and on demand as needed, the optimal set of generating units required to meet the Regulation Requirement. The software first calculates a Regulation Rank Price, based on estimates of Time-on-

Regulation Credits, Regulation Service Credits, estimated Regulation Opportunity Costs, Regulation Capability and other factors, as specified below, that consider the impact of Regulation assignment on the Real-Time Energy Market. An interim Regulation Clearing Price is then calculated and the Regulation Rank Prices are updated using this interim Regulation Clearing Price to recognize that actual payments for Regulation are based upon the Regulation Clearing Price and not the Regulation offer price. The software continues to iterate in this manner until convergence is reached, resulting in an optimal selection of generating units for Regulation assignment. The ISO utilizes the output from this software when evaluating the set of generating units for Regulation assignment. In the event that one or more generating units to be selected have equal Regulation Rank Prices, the ISO shall select the generating unit for Regulation assignment with the largest Regulation Capability. Details of the process and calculations are described below.

(1) At the start of each operating hour, the ISO calculates an initial Regulation Rank Price for each eligible unit offering to provide Regulation using the ISO's Regulation assignment software. The initial Regulation Rank Price for each unit is equal to the sum of the following calculations divided by that unit's Regulation Capability:

(a) Time-on-Regulation Credit estimate calculated as the product of the Regulation Capability times the Regulation offer price;

(b) Regulation Service Credit estimate is set equal to the Time-on-Regulation Credit estimate to meet the 50/50 revenue mix objective as determined by the ISO in accordance with procedures specified in the ISO New England Manuals and ISO New England Administrative Procedures;

(c) Regulation Opportunity Cost estimate calculated as the product of the opportunity cost MW times the opportunity cost price differential where:

(i) Opportunity cost MW is calculated as the absolute value of the difference between the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by Economic Max and Economic Min, and EstRegGen.

(ii) EstRegGen is the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by RSETHI and RSETLO. RSETHI is equal to the Regulation High Limit – Regulation Capability. RSETLO is equal to the Regulation Low Limit + Regulation Capability.

(iii) To more accurately estimate the actual Regulation Opportunity Cost that will be paid, EstRegGen is further constrained as follows to account for units with large regulating ranges and slow response rates: if actual generation is less than EstRegGen and EstRegGen is greater than RSETLO, then

EstRegGen is constrained up by the greater of (actual output + (SlowWideTime * Automatic Response Rate)) and RSETLO; if actual generation is greater than EstRegGen and EstRegGen is less than RSETHI, then EstRegGen is constrained down by the lesser of (actual output – (SlowWideTime * Automatic Response Rate)) and RSETHI. The SlowWideTime is determined by the ISO based upon empirical studies. The initial SlowWideTime value, and subsequent updates, shall be posted on the ISO's website.

(iv) Opportunity cost price differential is calculated as the absolute value of the difference between the average offer price of the opportunity MW and the Real-Time nodal LMP of the unit.

(d) Lookahead penalty estimate. The lookahead calculation assigns a cost penalty to units in the selection process if there is a change in energy offer prices near EstRegGen. It is calculated as 0.17 multiplied by the greater of:

(i) the unit's energy offer price at a higher output level (LookupRegGen as defined below) minus its energy offer price at EstRegGen, multiplied by (LookupRegGen – EstRegGen);

and

(ii) the unit's energy offer price at EstRegGen minus its energy offer price at a lower output level (LookdownRegGen as defined below), multiplied by (EstRegGen - LookdownRegGen),

where,

LookupRegGen = (EstRegGen + (LookAheadMinutesUp * Automatic Response Rate)) as bounded by Regulation High Limit; and

LookdownRegGen = (EstRegGen – (LookAheadMinutesDown * Automatic Response Rate) as bounded by Regulation Low Limit),

And where the initial values of LookAheadMinutesUp and LookAheadMinutesDown, and subsequent updates, will be posted on the ISO's website.

(e) A tiebreaker adder is calculated for both pool-scheduled and Self-Scheduled Regulation units. The tiebreaker adder is equal to a tiebreaker multiplier (.000001) times the difference between a tiebreaker megawatt reference value (500 MW) and the Regulation Capability of the unit.

For Self-Scheduled Regulation, all values calculated under this Section III.1.11.5(b)(1) are set equal to zero except for the tiebreaker adder.

(2) The ISO's Regulation assignment software creates an initial merit order stack of eligible Regulation Capability by sorting the generating units by the initial Regulation Rank Prices calculated under Section III.1.11.5(b)(1) in ascending order. Generating units are then selected in rank order until the Regulation Requirement is met. An initial Regulation Clearing Price is then calculated based upon the highest Regulation offer price associated with the initial set of generating units selected to meet the Regulation Requirement. Updated Regulation Rank Prices are then recalculated for generating units with Regulation offer prices that are less than the initial Regulation Clearing Price by substituting the initial Regulation Clearing Price for the generating unit's Regulation offer price, recalculating the Time-On-Regulation Credit and the Regulation Service Credit estimates; adding the

originally calculated values under Sections III.1.11.5(b)(1)(c), (d) and (e) to these recalculated values and dividing this total by the unit's Regulation Capability. These updated Regulation Rank Prices are utilized along with the initial Regulation offer prices that are greater than or equal to the initial Regulation Clearing Price to create an updated generating unit list sorted by ascending Regulation Rank Prices. An updated Regulation Clearing Price is then calculated and the software continues to iterate in this manner until convergence is reached producing an optimal generating unit rank order list for use in assigning Regulation.

(3) Shortly after the start of an hour and during the hour as needed, the ISO updates the generating unit rank order list using the ISO's Regulation assignment software based on any changes to Regulation Capability eligibility and other current information, including any changes to Self-Schedule Regulation. The ISO uses this updated Regulation rank order list to assign Regulation for the upcoming hour and to make changes to Regulation assignments within the hour.

(c) The ISO shall dispatch Resources for Regulation by sending Regulation signals and instructions to Resources from which Market Participants, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, have offered Regulation service. Market Participants shall comply with Regulation dispatch signals and instructions transmitted by the ISO and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources supplying load in the New England Control Area as close to desired output levels as practical, consistent with Accepted Electric Industry Practice.

III.1.11.6 [Reserved]

III.1.12 Dynamic Scheduling. Dynamic Scheduling can be requested and may be implemented in accordance with the following procedures:

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

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

(c) An entity requesting dynamic scheduling shall be responsible for arranging for the provision of signal processing and communication from the generating unit and other participating Control Area and complying with any other procedures established by the ISO regarding dynamic scheduling as set forth in the ISO New England Manuals. Allocation of costs associated with dynamic scheduling shall be determined and filed with the Commission following the first request.

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

III.2 Calculation Of Locational Marginal Prices and Real-Time Reserve Clearing Prices

III.2.1 Introduction. The ISO shall calculate the price of energy at Nodes, Load Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day.

III.2.2 General. The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors when applicable.

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

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

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

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.4, every offer of energy by a Market Participant from a generating Resource, an External Transaction purchase Resource and a Dispatchable Asset Related Demand Resource that is following economic dispatch instructions of the ISO will be utilized in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator. Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and locational Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the most recent power flow solution produced by the State Estimator, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Determination of Energy Offers Used in Calculating Real-Time Prices and Real-Time Reserve Clearing Prices.

(a) During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market.

(b) To determine the energy offers submitted to the New England Markets that shall be used during the Operating Day to calculate the Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall determine which generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources are following its economic dispatch instructions. A generating Resource, External

Transaction purchase or Dispatchable Asset Related Demand Resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-Time Prices if:

(i) the applicable Supply Offer price submitted by a Market Participant for energy from the generating Resource or External Transaction purchase is less than or equal to the Dispatch Rate associated with that generating Resource or External Transaction purchase; and

(ii) the applicable Demand Bid price submitted by a Market Participant for energy from the Dispatchable Asset Related Demand Resource is greater than or equal to the Dispatch Rate associated with that Dispatchable Asset Related Demand Resource; and

(iii) the generating Resource, other than a Fast Start Generator, is operating above its Economic Minimum Limit; or

(iv) the Fast Start Generator is operating at or above its Economic Minimum Limit and the applicable Supply Offer price submitted by a Market Participant for energy from the Fast Start Generator is less than or equal to the Dispatch Rate associated with that Fast Start Generator; or

(v) the generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource is specifically requested to operate or reduce consumption by the ISO's dispatcher and the associated energy offers or bids submitted are otherwise eligible to be included in the calculation of Real-Time Location Marginal Prices.

(c) In determining whether a generating Resource or External Transaction purchase satisfies the condition described in III.2.4(b), the ISO will determine the Supply Offer price associated with an energy offer by comparing the actual megawatt output of the generating unit or External Transaction purchase with the Market Participant's Supply Offer price curve for that generating unit or External Transaction purchase. Because of practical generator response limitations, a generating unit whose megawatt output is not more than ten percent above the megawatt level specified in the Supply Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

(d) In determining whether a Dispatchable Asset Related Demand Resource satisfies the condition described in III.2.4(b), the ISO will determine the Demand Bid price associated with a Demand Bid by comparing the actual megawatt consumption of the Dispatchable Asset Related Demand Resource with the Market Participant's Demand Bid price curve for that Dispatchable Asset Related Demand Resource. Because of practical Dispatchable Asset Related Demand Resource response limitations, a Dispatchable Asset Related Demand Resource whose megawatt consumption is greater than or equal to ninety percent of the megawatt level specified in the Demand Bid price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy demand bid price used in the calculation of Real-Time Prices shall not be lower than the applicable Dispatch Rate.

III.2.5 Calculation of Real-Time Nodal Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.8; and (5) the effect on transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node.

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

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

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Reserved for future use.

III.2.6 Calculation of Day-Ahead Nodal Prices.

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

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

External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Node.

The process for clearing External Nodes differs from the process for clearing other Nodes in that, in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

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

(i) All fixed External Transaction sales are considered to be dispatchable at $1,000/MWh;

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

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

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

(i) All fixed External Transaction purchases are considered to be dispatchable at $0/MWh and reduced pro-rata, as applicable, until power balance is reached;

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

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

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

(a) The ISO shall calculate Zonal Prices for each Load Zone for both the Day-Ahead and Real-Time Energy Markets for each hour using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone shall be determined in accordance with applicable Market Rules and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

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

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

(d) A Reserve Zone shall be established by the ISO which represent the remaining areas within the New England Transmission System that are not included within the Reserve Zones established under Section III.2.7(c).

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

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

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

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

Reliability Region and electrically located within another Reliability Region shall be located within the Reliability Region to which they are electrically located.

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

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time

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

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

(a) The ISO shall determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of Real-Time Nodal Prices specified under Section III.2.5, based on the system conditions described by the most recent power flow solution produced by the

State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available generating Resources and

Dispatchable Asset Related Demand Resources with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMSNR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

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

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

(i) local TMOR RCPF = $250/MWh;

(ii) system TMOR RCPF = $100/MWh;

(iii) system TMNSR RCPF = $850/MWh;

(iv) system TMSR RCPF = $50/MWh.

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

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

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

III.2.8 Hubs and Hub Prices.

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

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

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

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

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

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

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

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

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

ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

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

III.2.9B Final Day-Ahead Energy Market Results

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

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

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

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

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

[Sheet reserved for future use.]

III.3 Accounting And Billing

III.3.1 Introduction. This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

(a) For each Market Participant for each hour, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the ISO Day-Ahead Energy Market. To accomplish this, the ISO will perform calculations to determine the following.

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

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

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

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

(b) For each Market Participant for each hour, the ISO will determine a Real-Time Energy Market position. To accomplish this, the ISO will perform calculations to determine the following:

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

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

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

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

(c) For each Market Participant for each hour, the ISO will determine the difference between the Day-Ahead Energy Market position (Section III.3.2.1(a)) and the Real-Time Energy Market position (Section III.3.2.1(b)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market. To accomplish this, the ISO will perform calculations to determine the following:

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

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

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

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each hour a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between the Real-Time Locational Adjusted Net Interchange and the Day-Ahead Locational Adjusted Net Interchange.

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

Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

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

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

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

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

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

(h) For each hour for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in Loss Revenue (Section III.3.2.1(g)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the

Market Participant's pro rata share of the sum of all Market Participants' Real-Time Adjusted Load Obligations.

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

(j) Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the

Real-Time Energy Market, calculated as the amount to be delivered in each hour multiplied by the difference between the Loss Component of the hourly Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the hourly Real-Time Price at the source point or New England Control Area boundary source interface.

(k) For each hour, the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at each External Node by the associated Real-Time Locational Marginal Price and then summing these values for all External Nodes.

(l) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(k)). The Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations and Real-Time Generation Obligations over all Locations, measured as absolute values.

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

III.3.2.2 Regulation.

(a) Each Market Participant shall have an hourly Regulation obligation equal to its pro rata share of the New England Control Area Regulation requirements for the hour, based on the Market Participant's total Real-Time Load Obligation in the New England Control Area for the hour. A Market Participant that does not meet its hourly

Regulation obligation through its own Resources or through an appropriate bilateral transaction, shall be charged for Regulation dispatched by the ISO to meet such obligation at the Regulation Clearing Price determined in accordance with paragraph (e) of this Section, plus the amounts, if any, described in paragraph (d) and (j) of this Section.

(b) A Market Participant supplying Regulation at the direction of the ISO in excess of its hourly Regulation obligation shall be credited for Time-On-Regulation Megawatts at the higher of (i) the Regulation Clearing Price or (ii) the Regulation Supply Offer price of the generating Resource supplying Time-On-Regulation Megawatts, plus the unit-specific Regulation Opportunity Cost of the generating Resource supplying the Time-On-Regulation Megawatts, as determined by the ISO in accordance with procedures specified in the ISO New

England Manuals and ISO New England Administrative Procedures.

(c) A Market Participant supplying Regulation at the direction of the ISO shall receive a credit for Regulation Service Megawatts at the higher of (i) the Regulation Clearing Price or (ii) the Regulation Supply Offer price of the generating Resource supplying Regulation Service Megawatts, multiplied by the Capacity-to-Service Ratio. The Capacity-to-Service Ratio is described under Subsection (h).

(d) Each Market Participant shall be charged its pro rata share of the total Regulation Service Credits for the hour, based upon the Market Participant's total Real-Time Load Obligation in the New England Control Area for the hour.

(e) The Regulation Clearing Price shall be determined by the ISO. The Regulation Clearing Price for each hour shall be equal to the time-weighted average of all interval based Regulation Clearing Prices calculated within the hour. The Regulation Clearing Price for each interval within the hour shall be equal to the highest Regulation Supply Offer price of any generating Resources selected to provide Regulation in that interval. Regulation Clearing Prices shall be posted and finalized by the ISO in accordance with Section III.2.9A of this Market Rule.

(f) A Market Participant's Regulation Service Megawatts shall be determined by the ISO. A Market Participant's hourly Regulation Service Megawatts for each generating Resource providing Regulation shall be equal to the sum of the absolute value of the generation movement, in megawatts, towards the Regulation set point, such movement calculated in four second intervals based upon the generating Resource's Automatic Response Rate.

(g) A Market Participant's Time-on-Regulation Megawatts shall be determined by the ISO. A Market Participant's hourly Time-on-Regulation Megawatts for each generating Resource providing Regulation shall be equal to the Regulation capability provided multiplied by the minutes of Regulation provision in the hour, divided by sixty.

(h) The Capacity-to-Service Ratio shall be determined by the ISO. The Capacity-to-Service Ratio is the relationship between Regulation capability provided and Regulation Service Megawatts provided in an hour. Based on historical analysis, on average, one megawatt of Regulation capability will produce ten megawatts of Regulation Service Megawatts. Based on this relationship, the Capacity-to-Service Ratio shall initially be set equal to 0.1 such that the revenue associated with Time-on-Regulation Megawatts and Regulation Service Megawatts associated with a Resource providing Regulation shall be equally split. The revenue split assumption and the Capacity-to-Service ratio may be changed from time to time and such changes shall be filed with the Commission for approval.

(i) In determining the credit under subsection (b) to a Market Participant that is selected to provide Regulation and that actively follows the ISO's Regulation signals and instructions, the unit-specific Regulation Opportunity Cost of a generating Resource shall be determined for each hour that the ISO requires a generating Resource to provide Regulation and shall be equal to the product of (i) the deviation of the generating Resource's output necessary to follow the ISO's Regulation signals from the generating Resource's expected output level if it had been dispatched in economic merit order multiplied by (ii) the absolute value of the difference between the Real-Time Price at the generation Node for the generating Resource and the megawatt weighted average Supply Offer price for the energy associated with the deviation of the generating Resource's expected output level if it had been dispatched in economic merit order.

(j) Amounts credited for Regulation Opportunity Cost in an hour shall be allocated and charged to each Market Participant that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in MWhs during that hour.

III.3.2.3 NCPC Credits. The following paragraphs describe the calculation of NCPC Credits and NCPC Charges. Additional information on these calculations may be found in Appendix F of this Market Rule.

(a) Except as otherwise provided for under Section III.3.2.3(f), Market Participants' Pool-Scheduled Resources capable of providing Operating Reserve or Replacement Reserve shall be credited as specified below (an "NCPC Credit") based on the prices offered for the operation of such Resources, provided that the Resources were available for the entire time specified in the Offer Data for such Resource.

(b) The following determination shall be made for the Day Ahead Energy Market:

(i) For each Pool-Scheduled generating Resource that is scheduled in the Day-Ahead Energy Market: the total offered price for Start- Up and No-Load Fees and energy, determined on the basis of the Resource's scheduled output, shall be compared to the total value of that Resource's scheduled energy output as determined by the Day-Ahead Energy Market and the Day-Ahead Prices applicable to the relevant generation Node or External Node in the Day-Ahead Energy Market. If the total offered price summed over all hours for the Operating Day exceeds the total value summed over all hours for the Operating Day, the difference shall be credited to the Market Participant.

(ii) Other Day-Ahead NCPC Credits shall be calculated as specified in Section III.F.2.

(c) Except as otherwise provided for under Section III.6.4.4, the sum of the foregoing credits calculated in accordance with Section III.3.2.3(b) shall be the “NCPC

Charge" in the Day-Ahead Energy Market in each Operating Day.

(d) The NCPC Charge in the Day-Ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its hourly Day- Ahead Load Obligation in for that Operating Day except that, any NCPC Charge associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(e) At the end of each Operating Day, the following determinations shall be made:

(i) for each eligible hour for each synchronized Pool-Scheduled Resource of each Market Participant that operates as requested by the ISO and that is not committed for synchronized condensing: The total offered price, as calculated in accordance with Section III.F.2.1.9, shall be compared to the total value of that Resource's energy in the Real-Time Energy Market, as calculated in accordance with Section III.F.2.1.13. If the total offered price exceeds the total value, the difference shall be credited to the Market Participant as a Real-Time NCPC Credit.

(ii) For each synchronized Pool-Scheduled or Self-Scheduled Dispatchable Asset Related Demand Resource of each Market Participant that is associated with pumping load and that operates as requested by the ISO in accordance with Section III.3.2.3(f): the total Real-Time costs of energy consumption, as calculated in accordance with Section III.F.2.4.10, shall be compared to the total bid amount of that Resource's energy consumption in the Real-Time Energy Market, as calculated in accordance with Section III.F.2.4.7. If the total Real-Time costs exceed the total bid amount, the difference shall be credited to the Market Participant as a Real-Time NCPC Credit.

(iii) For each Pool-Scheduled External Transaction sale of each Market Participant that operates as requested by the ISO: the difference between a Market Participant's Real-Time bid price and Real-Time costs as determined pursuant to Section III.F.2 shall be credited to the Market Participant as a Real-Time NCPC Credit.

For purposes of this Section, a Market Participant is deemed to operate as requested by the ISO if it follows dispatch instructions. A generator is considered to be following a dispatch instruction if the actual output of the generator is not greater than 10% above its desired dispatch point and is not less than 10% below its desired dispatch point for each interval in the hour. Generators with an Economic Max less than or equal to 50 MWs are considered to be following a dispatch instruction if the actual output of the generator is not greater than 5 MWs above its desired dispatch point and is not less than 5 MWs below its desired dispatch point for each interval in the hour. If the generator violates this criterion in any interval during the hour, the generator is considered to be not following dispatch instructions for the entire hour.

(f) A Market Participant's Pool-Scheduled Resource or Self-Scheduled generating Resource, the output of which is reduced or suspended at the request of the ISO for the purpose of maintaining appropriate levels of

Operating Reserve or for the provision of voltage support, shall be credited in an amount equal to the following:

For generating Resources, the credit for each hour of reduced or suspended operation is:

Posturing Credit = (PAG - AG) x (ULMP - UB) – RC where:

PAG equals the estimated hourly generation had the generator not responded to dispatch orders to reduce or suspend operation taking any limited energy restrictions into account, such estimated hourly generation to be determined in accordance with procedures defined in the ISO New England Manuals;

AG equals the actual output of the generating Resource;

ULMP equals the Real-Time Price associated with the generating Resource that is reduced or suspended for each hour;

UB equals the Supply Offer price associated with PAG for that generating Resource whose output is reduced or suspended;

RC equals any Regulation credits from Section III.3.2.2(i); and where ULMP - UB shall not be negative and Posturing Credit shall not be negative.

The amount, in MW, of a Market Participant's Pool-Scheduled Dispatchable Asset Related Demand Resource or Self-Scheduled Dispatchable Asset Related Demand Resource that is associated with pumping load which is maintained out of economic merit at the request of the ISO for the purpose of maintaining appropriate levels of Operating Reserve, shall be credited in accordance with Section III.3.2.3(b) and III.3.2.3(e).

(g) Except as otherwise provided for under Section III.6.4.4, the sum of the foregoing NCPC Credits, plus any Cancellation Fees paid in accordance with Section III.1.10.2(d), such Cancellation Fees to be applied to the Operating Day for which the unit was scheduled, shall be the non-synchronized condensing NCPC Charge for the Real-Time Energy Market in each Operating Day.

(h) The non-synchronized condensing and synchronized condensing NCPC Charge for the Real-Time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day;

(ii) generation deviations for Pool-Scheduled Resources not following ISO dispatch instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following ISO dispatch instructions and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that, any NCPC Charge associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services

Tariff. For the purposes of calculating generation deviations, if a generation resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating Real-Time NCPC Charges. For the purposes of calculating Real-Time NCPC Charges, any difference between the actual consumption (Real-Time Load Obligation) of Dispatchable Asset Related Demand Resources and Dispatchable Asset Related Demand Bids that clear in the Day-Ahead Energy Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation.

(i) At the end of each Operating Day, Market Participants shall be credited on the basis of their offered prices for synchronized condensing for any hydropower or combustion turbine units operated as synchronous condensers but producing no energy.

(j) The sum of the foregoing NCPC Credits as specified in Section III.3.2.3(i) shall be the NCPC Charge for synchronized condensing in the Real-Time Energy Market for the Operating Day in the New England Control Area.

(k) **[Reserved]**

Reserved for future use.

Reserved for future use.

Reserved for future use.

Reserved for future use.

III.3.2.4 Transmission Congestion. Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(f) of this Market Rule.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

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

Scheduled amounts not following ISO dispatch instructions and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generation Resources shall have a 5% or 5 MWh threshold when determining such deviations.

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

III.3.2.6A New Brunswick Security Energy. New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396) tie line and Orrington-Lepreau (390) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of New England Network Load or in such other manner as may be described in ISO New England Manual M-28 (Market Rule 1 Accounting). Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing. The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6 of this Market Rule, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion. Non-Market Participant Transmission Customers shall be charged or credited for Congestion Costs as specified in Section III.1 of this Market Rule.

III.3.4.2 Transmission Losses. Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing. The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing. The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 Eligible Data. The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily UCAP Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions. The ISO will accept revisions to asset specific meter data, daily UCAP Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines for submittal of that data have passed, except as provided in Section III.3.8 of this Market Rule. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Reserves, Auction Revenue Rights allocations, ICAP Transition, Reliability Agreements, and the ISO Self-Funding Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of this Market Rule.

III.3.6.4 Meter Corrections Between Control Areas. For revisions to meter data associated with assets that connect the New England Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the New England Control Area and the other Control Area to maintain an accurate record of inadvertent energy flow.

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily UCAP Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of this Market Rule. Specific data submittal deadlines are detailed in the ISO New England Manuals.

(b) Errors on the part of the ISO in the administration of Market Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the Correction Limit.

III.3.7 Eligibility for Billing Adjustments.

(a) Errors in Market Participant's statements resulting from errors in settlement software, errors in data entry by ISO personnel, and settlement production problems, that do not affect the day-ahead schedule or real-time system dispatch, will be corrected as promptly as practicable. If errors are identified prior to the issuance of final statements, the market will be resettled based on the corrected information.

(b) Calculations made by scheduling or dispatch software, operational decisions involving ISO discretion which affect scheduling or real-time operation, and the ISO's execution of mandatory dispatch directions, such as self-schedules or external contract conditions, are not subject to retroactive correction and resettlement. The ISO will settle and bill the Day-Ahead Energy Market as actually scheduled and the Real-Time Energy Market as actually dispatched. Any post-settlement issues raised concerning operating decisions related to these markets will be corrected through revision of operations procedures and guidelines on a prospective basis.

(c) While errors in reporting hourly metered data may be corrected (pursuant to Section III.3.8), Market Participants have the responsibility to ensure the correctness of all data they submit to the market settlement system.

(d) Disputes between Market Participants regarding settlement of internal bilateral transactions shall not be subject to adjustment by the ISO, but shall be resolved directly by the Market Participants unless they involve an error by the ISO that is subject to resolution under Section III.3.7(a).

(e) Billing disputes between Market Participants and the ISO or Non-Market Participants and the ISO shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

(f) Criteria for Meter Data Errors to be eligible for a Requested Billing Adjustment. In order to be eligible to submit a Requested Billing Adjustment due to a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process, a Market Participant must satisfy one of the following two conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than thirty-six (36) days prior to the Correction Limit for Directly Metered Assets and no later than two (2) days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; or (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader and reported to the ISO by the Meter Data Error RBA Submission Limit, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWH per Asset over a calendar month. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website.

(b) Within three Business Days of the receipt by the ISO's Chief Financial Officer of an RBA form for a Meter Data Error, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Meter Data Error correction ("Notice of Meter Data Error Correction"), including, subject to the provisions of the ISO New England Information Policy, the specific details of the correction and the identity of the affected metering domains and the affected Host Participant Assigned Meter Readers. The "Notice of Meter Data Error Corrrection" shall identify a specific representative of the ISO to whom all communications regarding the matter are to be sent.

(c) In order for a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process to be eligible for correction, the Meter Data Error must satisfy one of the following conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host

Participant Assigned Meter Reader no later than 36 days prior to the Correction Limit for Directly Metered Assets and no later than two days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per asset over a calendar month; and (3) if the Meter Data Error involves only UCAP Peak Contribution values, the average of the daily Meter Data Errors involving UCAP Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

(d) For a Meter Data Error, the Host Participant Assigned Meter Reader must submit to the ISO corrected meter data for Directly

Metered Assets prior to the 46th calendar day after the Meter Data Error RBA Submission Limit. Corrected metered data for Profiled Load Assets and UCAP Peak Contribution values, must be submitted to the ISO by the Host Participant Assigned Meter Reader prior to the 87th calendar day after the Meter Data Error RBA Submission Limit. Corrected internal bilateral transactions data must be submitted to the ISO by a Market Participant prior to the 91st calendar day after the Meter Data Error RBA Submission Limit.

Any corrected data received after the specified deadlines is not eligible for use in the settlement process.

The Host Participant Assigned Meter Reader or Market Participant, as applicable, must confirm as part of its submission of corrected data that the eligibility criteria described in Section III.3.8(c) of Market Rule 1 have been satisfied.

To the extent that the correction of a Meter Data Error is for a Directly Metered Asset that affects multiple metering domains, all affected Host Participant Assigned Meter Readers or Assigned

Meter Readers must notify the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit that the corrected Directly Metered Asset data is acceptable to them in order for the ISO to use the corrected data in the final settlement calculations. The Host Participant Assigned Meter Reader for the Directly Metered Asset is responsible for initiating an e-mail to every affected Host Participant Assigned Meter Reader or Assigned Meter Reader in order to obtain such acceptance and shall coordinate delivery of such acceptance to the ISO. The Host Participant Assigned Meter Reader for the Directly Metered Asset is also responsible for submitting all corrected and agreed upon Directly Metered Asset data to the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit.

(e) After the submission of corrected meter and internal bilateral transactions data, the ISO will have a minimum of 30 calendar days to administer the final settlement based on that data. The results of the final settlement will then be included in the next Invoice containing Non-Hourly Charges (as that term is defined in the ISO New England Billing Policy) and the ISO will provide to the Chair of the NEPOOL Budget and Finance Subcommittee written notification that the final settlement has been administered.

III.4 Rate Table

III.4.1 Offered Price Rates. Day-Ahead energy, Real-Time energy, Regulation, Real-Time Operating Reserve, Forward Reserve, NCPC, Congestion Cost and transmission loss costs are based on offers and bids submitted to the ISO as specified in this Market Rule.

III.4.2 [Reserved.]

III.4.3 Emergency Energy Transaction. The pricing for Emergency energy and New Brunswick Security Energy purchases and sales will be determined in accordance with:

(a) an applicable agreement with an adjacent Control Area for Emergency and/or New Brunswick Security Energy purchases and sales, or

(b) arrangements made by the ISO with Market Participants, in accordance with procedures defined in the ISO New England Manuals, to purchase Emergency energy offered by such Market Participant from Resources that are not ICAP Resources. The ISO shall select offers to sell

Emergency energy made by Market Participants to the ISO on a least cost basis and the selected Market Participants shall receive payment for energy delivered at the higher of their offer price or the Real-Time Price at the applicable External Node. Such Emergency energy purchases from Market Participants shall not be eligible to set Real-Time Prices.

III.5 Calculation Of Transmission Congestion Revenue And Credits

III.5.1 Non-Market Participant Transmission Congestion Cost Calculation.

III.5.1.1 Calculation by ISO. When the transmission system is operating under constrained conditions, the ISO shall calculate Congestion Costs.

III.5.1.2 General. The basis for the Congestion Costs shall be the differences in the Congestion Component of the Locational Marginal Prices between points of delivery and points of receipt, as determined in accordance with Section III.2 of this Market Rule.

III.5.1.3 [Reserved.]

III.5.1.4 Non-Market Participant Transmission Customer Calculation. Congestion Costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each hour multiplied by the difference between the

Congestion Component of the hourly Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Congestion Component of the hourly Real-Time Price at the source point or New England Control Area boundary source interface. Non-Market Participants using Point-to-Point Transmission Service for deliveries through the New England Control Area shall be included in the determination of the Congestion Costs.

III.5.2 Transmission Congestion Credit Calculation.

III.5.2.1 Eligibility. Except as provided in Section III.A.6.5 of Appendix A, each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total monthly Transmission Congestion Revenues collected.

III.5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the FTRs held at the time of the constrained hour.

(b) FTRs shall be awarded to winning bidders in the FTR Auctions pursuant to Section III.7 and may be acquired in the subsequent bilateral market from FTR Holders.

(i) An entity that acquires an FTR through the FTR Auction shall automatically be recognized by the ISO as the registered FTR Holder of that FTR, subject to having already met the eligibility criteria for bidding in the FTR Auction. The registered FTR Holder shall be entitled to receive or be obligated to make FTR payments arising from such FTR in accordance with Section III.5.2.

(ii) An entity that acquires an FTR through the FTR Auction or through a subsequent bilateral transaction may elect to hold it, sell it in the FTR Auction or sell it bilaterally. The registered FTR Holder of an FTR sold in a bilateral transaction will continue to be the FTR Holder for that FTR unless it submits a confirmation of the sale to the ISO in accordance with the ISO New England Manuals and ISO New England Administrative Procedures. The ISO upon receipt of such a confirmation will transfer record ownership. The purchaser of an FTR in a bilateral transaction that is not recorded by the ISO receives only a contractual right against the seller of the FTR and has no rights or obligations in settlement or in the Energy market. An entity who subsequently acquires an FTR from an FTR Holder through a bilateral transaction must meet applicable financial assurance criteria to be the FTR Holder of that FTR and secure the associated rights and obligations. The ISO shall settle FTRs only with the registered FTR Holders. At any given time, each FTR shall have only one registered FTR Holder.

III.5.2.3 [Reserved.]

III.5.2.4 Target Allocation to FTR Holders. A target allocation of Transmission Congestion Credits for each FTR Holder shall be determined for all applicable FTRs. Each FTR shall be multiplied by the Day-Ahead Price Congestion Component differences for the associated receipt and delivery points. This calculation will result in a positive or negative FTR target allocation. All negative target allocations are obligations to pay. All positive target allocations will be summed for an FTR Holder for the month and compensated as Transmission Congestion Credits under Section III.5.2.5.

III.5.2.5 Calculation of Transmission Congestion Credits.

(a) The total Transmission Congestion Revenue available for the month shall be equal to the sum of: (i) the hourly Day-Ahead Congestion Revenue amounts for the month, (ii) the hourly Real-Time Congestion Revenue amounts for the month plus Congestion Costs collected under Section III.5.1.4, and (iii) the negative FTR target allocations calculated under Section III.5.2.4.

(b) The sum of all monthly positive target allocations, as determined in Section III.5.2.4, shall be compared to the

Transmission Congestion Revenue for the current month. If the sum of all monthly positive target allocations is less than the Transmission Congestion Revenue for the current month, the Transmission Congestion Credit for each FTR Holder shall be equal to its total monthly positive target allocation. All remaining Transmission Congestion Revenues from the current month shall be carried over to the end of the calendar year.

(c) If the sum of all the monthly positive target allocations is greater than the Transmission Congestion Revenue for the current month, each FTR Holder shall be assigned a share of the total Transmission Congestion Revenue for the current month in proportion to its total monthly positive target allocations.

III.5.2.6 Distribution of Excess Congestion Revenue. If there is any Transmission Congestion Revenue at the end of the calendar year, this amount shall be proportionally allocated to any remaining unpaid monthly positive target allocations plus interest on the unpaid monthly positive target allocations in the months of that year, but shall not exceed an amount equal to the unpaid monthly positive target allocation plus interest on the unpaid monthly positive target allocations in the months of the calendar year. Any remaining surplus Transmission Congestion Revenue shall be allocated to the entities who paid Congestion Costs in that calendar year in proportion to the amount of total Congestion Costs paid during the year.

III.6 Local Second Contingency Protection Resources

III.6.1 Definition. "Local Second Contingency Protection Resources" are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

III.6.2 Day-Ahead and Real-Time Energy Market. When establishing operating schedules, the ISO will select and identify Local Second Contingency Protection Resources on a not unduly discriminatory basis in accordance with the procedures defined in the ISO New England Manuals. ***Appendix A*** will determine which, if any, Supply Offers will be adjusted. The ISO will also record, in an auditable log, the reason the Resource was selected.

III.6.2.1 Special Constraint Resources. When establishing operating schedules, at the request of a Transmission Owner or distribution company in order to maintain area reliability, the ISO will commit and dispatch generating Resources to provide relief for constraints not reflected in the ISO's systems for operating the New England Transmission System or the ISO's operating procedures in accordance with the procedures defined in the ISO New England Manuals. The ISO will also record, in an auditable log, the designation of such generating Resource as a Special Constraint Resource and the name of the requesting Transmission Owner or distribution company. Any NCPC Charge associated with the Real-Time operation of the Special Constraint Resource is charged in accordance with the provisions of Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

III.6.3 [Reserved.]

III.6.4 Local Second Contingency Protection Resource NCPC Charges.

III.6.4.1 [Reserved.]

III.6.4.2 [Reserved.]

III.6.4.3 Calculation of Local Second Contingency Protection Resource NCPC Payments. Day-Ahead and Real-Time NCPC Credits for Local Second Contingency Protection Resources are determined in accordance with the provisions of paragraphs (a), (b), (c) and (e) in Section III.3.2.3, as applied to Pool-Scheduled Resources, but such credits shall not be included in NCPC Charges pursuant to Section III.3.2.3 and shall instead be allocated and charged in accordance with Section III.6.4.4. The Day-Ahead and Real-Time NCPC Credits for Local Second Contingency Protection Resources are subject to market power review and mitigation.

III.6.4.4 Calculation of Local Second Contingency Protection Resource NCPC Charges and Allocation of Fixed Cost Charges Associated with Reliability Agreements.

(a) The Day-Ahead NCPC Credits calculated in accordance with Section III.6.4.3 for Local Second Contingency Protection Resources are aggregated into an NCPC Charge and charged pro rata to each Market Participant in proportion to the sum of its Day-Ahead Load Obligations in MWhs for that Operating Day for Locations within the affected Reliability Region.

(b) The Real-Time NCPC Credits calculated in accordance with Section III.6.4.3 for Local Second Contingency Protection Resources are aggregated into an NCPC Charge and charged to each Market Participant in proportion to the sum of its Real-Time Load Obligations (excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resource (pumps only) operation that is above its Minimum Consumption Limit) in MWhs during the Operating Day within the affected Reliability Region. For hours for which a Local Second Contingency Protection Resource NCPC Charge is calculated and an Emergency energy sale is being made by the ISO, the amount (MWh) of Emergency energy sales will be included in the above calculation, with a proportional share attributable to the Emergency energy sale being added to the purchasing Control Area's cost for Emergency energy.

(c) Any monthly fixed-cost charges paid to Resources pursuant to Reliability Agreements negotiated under *Appendix A*, Section III.A.6 and Exhibit 2 shall be allocated and charged pro rata to Market Participants and Non-Market Participants with Network Load in proportion to the sum of their Network Load during that month within the affected Reliability Region.

III.7 Financial Transmission Rights Auctions

III.7.1 Auctions of Financial Transmission Rights. Periodic auctions ("FTR Auctions") to allow Eligible FTR Bidders to acquire or FTR Holders to sell FTRs shall be conducted by the ISO in accordance with the provisions of this Section. Non-Market Participants that want to participate in the FTR Auction or to become an FTR Holder via the secondary market and have satisfied the applicable financial assurance criteria will be charged a one time FTR Registration Fee of $5,000 This fee may be superceded by a future provision in the Transmission, Markets and Services Tariff.

III.7.1.1 Auction Period and Scope of Auctions.

(a) Initially, FTR Auctions shall be held on a monthly basis followed by the introduction of long-term FTR Auctions. Long-term auctions shall be introduced no later than October 1, 2003. The ISO shall provide notice of the initial long-term auction at least thirty (30) days prior to the opening of the auction-quoting period for such long-term auction as described in Section III.7.1.2(a). At the time of such notice, the ISO shall post a schedule for future long-term auctions and the percent of the feasible FTRs that will be available in such long-term auctions. Such schedule shall coordinate the start and end dates of the long-term FTRs to be auctioned with those of the long-term FTRs of neighboring Control Areas. During the period prior to the long-term auctions, the entire transfer capability of the New England Transmission System will be made available to support the sale of FTRs with a term of one month in the monthly FTR Auctions.

(b) Following the initial auctions described above, FTR auctions shall be held on both an annual and monthly basis.

Fifty percent of the feasible FTRs that can be made available with a term of one year shall be made available in the annual FTR Auction. After the annual FTR Auction has been conducted, the remaining feasible FTRs, each having a term of one month, shall be made available in the monthly FTR Auctions. Within two years from the March 1, 2003, the ISO will evaluate making available FTRs with a term of more than one year (in one-year increments).

III.7.1.2 Frequency and Time of FTR Auctions.

(a) Annual (initial long-term) auctions: The bid and offer period shall open five business days before the first business day of the month preceding the period in which the FTRs are to be effective for a five business day auction-quoting period that closes at noon on the fifth business day.

(b) Monthly auctions: The bid and offer period shall open beginning fifteen business days before the first business day of the month preceding the period in which the FTRs are to be effective for a five business day auction-quoting period that closes at noon on the fifth business day.

III.7.2 Financial Transmission Rights Characteristics.

III.7.2.1 Reconfiguration of Financial Transmission Rights. Using an appropriate linear programming model, the ISO shall reconfigure the FTRs offered or otherwise available for sale in any auction to maximize the value to the bidders of the FTRs sold, provided that any FTRs acquired at auction shall be simultaneously feasible in combination with those FTRs outstanding at the time of the auction and not sold in the auction. The linear programming model shall, while respecting transmission constraints and the maximum megawatt quantities of the bids and offers, select the set of simultaneously feasible FTRs with the highest total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers.

III.7.2.2 Specified Locations. Auction bids for FTRs may specify any combination of receipt and delivery locations represented in the State Estimator model for which the ISO calculates and posts Locational Marginal Prices. Auction bids may specify receipt and delivery points from locations outside of the New England Control Area to locations inside the New England Control Area, from locations within the New England Control Area to locations outside of the New England Control Area, or to and from locations within the New England Control Area. Congestion over interfaces associated with non-PTF external tie lines is not subject to LMP-based congestion management and, therefore, no FTRs across such interfaces will be included in the FTR Auctions.

III.7.2.3 Transmission Congestion Revenues. FTRs shall entitle holders thereof to credits only for Transmission Congestion Revenue, and shall not confer a right to credits for payments arising from or relating to transmission congestion made to any entity other than the ISO.

III.7.2.4 [Reserved.]

III.7.3 Auction Procedures.

III.7.3.1 Role of the ISO. FTRs auctions shall be conducted by the ISO in accordance with standards and procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures, such standards and procedures to be consistent with the requirements of this Market Rule.

III.7.3.2 [Reserved.]

III.7.3.3 [Reserved.]

III.7.3.4 On-Peak and Off-Peak Periods. The ISO will conduct separate auctions simultaneously for on-peak and off-peak periods. On-peak FTRs shall cover the periods from 7:00 a.m. up to the hour ending at 11:00 p.m. on Mondays through Fridays, except holidays as defined in the ISO New England Manuals and ISO New England Administrative Procedures. Off-peak FTRs shall cover the periods from 11:00 p.m. up to the hour ending 7:00 a.m. on Mondays through Fridays and all hours on Saturdays, Sundays, and NERC holidays as defined in the ISO New England Manuals and ISO New England Administrative Procedures. Each bid shall specify whether it is for an on-peak or off-peak period.

III.7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase FTRs shall be submitted during the applicable period set forth in Section III.7.1.2, and shall be in the form specified by the ISO in accordance with the requirements set forth below.

(b) Offers to sell shall identify the specific FTRs, by megawatt quantity and receipt and delivery points, offered for sale. An offer to sell a specified megawatt quantity of FTRs shall constitute an offer to sell a quantity of FTRs equal to or less than the specified quantity. An offer to sell may not specify a minimum quantity being offered. Each offer may specify a reservation price, below which the offeror does not wish to sell the FTR. Offers shall be subject to such applicable standards for the financial assurance of the offeror or for the posting of security for performance as the ISO shall establish.

(c) Bids to purchase shall specify the megawatt quantity, price per megawatt, and receipt and delivery points of the FTR that the bidder wishes to purchase. A bid to purchase a specified megawatt quantity of FTRs shall constitute a bid to purchase a quantity of FTRs equal to or less than the specified quantity. A bid to purchase may not specify a minimum quantity that the bidder wishes to purchase. A bid may specify as receipt or delivery points any Location for which the ISO calculates and posts Locational Marginal Prices in accordance with Section III.2 of this Market Rule and may include FTRs for which the associated Transmission Congestion Credits may have negative values. Bids shall be subject to such applicable standards for the financial assurance of the bidder or for the posting of security for performance as the ISO shall establish.

(d) Bids and offers shall be specified to the nearest 0.1 megawatt and the quantity shall be greater than zero.

III.7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of each bidding period, the ISO will create a base FTR power flow model that includes all outstanding FTRs that have previously been awarded for the period for which the auction was conducted and that were not offered for sale in the auction. The base FTRs model also will include estimated uncompensated parallel flows into each interface point of the New England Control Area and estimated scheduled transmission outages.

(b) In accordance with the requirements of this Section and subject to all applicable transmission constraints and reliability requirements, the ISO shall determine the simultaneous feasibility of all outstanding FTRs not offered for sale in the auction and of all FTRs that could be awarded in the auction for which bids were submitted. The winning bids shall be determined from an appropriate linear programming model that, while respecting transmission constraints and the maximum megawatt quantities of the bids and offers, selects the set of simultaneously feasible FTRs with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected FTRs and there are insufficient FTRs to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the FTRs that can be awarded.

(c) FTRs shall be sold at the market-clearing price for FTRs between specified pairs of receipt and delivery points, as determined by the bid value of the marginal FTR that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all FTR paths based on the bid value of the marginal FTRs, which are those FTRs with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each FTR's path relative to the marginal FTRs' paths flow sensitivities on the binding transmission constraints.

III.7.3.7 Announcement of Winners and Prices.

(a) Within four business days after the close of a monthly auction and six business days after the close of an annual or initial long-term auction, the ISO shall post the winning bidders, the megawatt quantity, and the receipt and delivery points for each FTR awarded in the auction and the price at which each FTRs was awarded. The FTR awards and prices shall be final as posted and not subject to correction or other adjustment, and shall be used for purposes of settlement, except as provided in subsections (c) and (d).

(b) Before posting the final FTR awards and prices, the ISO shall make a good faith effort when clearing the FTR Auction to discover and correct any errors that may occur due to database, software or similar errors of the ISO or its systems.

(c) If the ISO determines based on a reasonable belief that there may be one or more errors in the final FTR awards and prices or if no FTR awards or prices are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 11:59 p.m. of the third business day following the applicable posting deadline specified in subsection (a), a notice that the FTR awards and prices are provisional and subject to correction or unavailable for initial publishing. The ISO shall confirm within three business days of posting a notice pursuant to this subsection whether there was an error in the FTR awards an prices and shall post a notice stating its findings.

(d) Within three business days after posting an initial notice pursuant to subsection (c); the ISO shall either: (1) publish final or corrected FTR awards and prices, or (2) in the event that the ISO is unable to calculate and post final or corrected FTR awards and prices due to exigent circumstances not contemplated in this market rule, make an emergency filing with the Commission detailing the exigent circumstance, which will not allow final FTR awards and prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

(e) Results of the on-peak auction and off-peak auction will be posted separately. The ISO shall not disclose the price specified in any bid to purchase or the reservation price specified in any offer to sell.

III.7.3.8 Auction Settlements. All buyers and sellers of FTRs between the same points of receipt and delivery shall pay or be paid the market-clearing price, as determined in the auction, for such FTRs.

III.7.3.9 Allocation of Auction Revenues. All auction revenues, net of payments to entities selling FTRs into the auction, shall be allocated as specified under Appendix C of this Market Rule.

III.7.3.10 Simultaneous Feasibility. The ISO shall make the simultaneous feasibility determinations specified herein using appropriate power flow models of contingency-constrained dispatch. Such determinations shall take into account outages and expected configuration of transmission facilities and outages of individual generating units to the extent that such outages impact voltage or stability limits and shall be based on reasonable assumptions about the configuration and availability of transmission capability during the period covered by the auction. The goal of the simultaneous feasibility determination shall be to ensure that there are sufficient Transmission Congestion Revenues to satisfy all FTR obligations for the auction period under expected conditions.

III.7.3.11 [Reserved.]

III.7.3.12 Financial Transmission Rights in the Form of Options. When the ISO has the necessary software and hardware, the FTR Auctions shall allow for the acquisition of FTRs that do not create potential obligations to pay.

III.7.3.13 FTR Secondary Trading Market. FTR Holders may trade FTRs on the secondary market and have these settled using the ISO systems. The ISO systems shall only allow FTRs to be sub-divided into multiple FTRs with; i) the same points of injection and withdrawal; ii) different megawatt amounts the sum of which does not exceed the original FTR MW amount; and iii) different start and end dates where the start and end dates are the same as or within the start and end dates of the original FTR. FTRs may be reconfigured only through FTR Auctions.

III.7.3.14 Temporary FTR Surcharge. Beginning with the first monthly statement for Non-Hourly Charges, as described and defined in Section 2.2 of the ISO New England Billing Policy, issued by the ISO after the Commission approves the settlement agreement filed in Docket No. ER04-798, the ISO shall collect through its normal settlement process, from all entities awarded FTRs in the auctions conducted by the ISO following Commission approval of the settlement agreement, a surcharge of one and one-tenth percent (1.1%) on the absolute value of all awarded dollars in FTR auctions (the "FTR Surcharge"), including positive and negative awarded dollars. Sellers of FTRs and FTR sales outside the auction shall not be subject to the FTR Surcharge. The ISO shall collect the FTR Surcharge until it has received $2,599,781 plus all interest costs associated with borrowing such amount payable by the ISO to its lenders under its revolving line of credit. The ISO will post monthly on its website information regarding the pay-down of such borrowing and interest from proceeds of the FTR Surcharge. Amounts collected pursuant to the FTR Surcharge in the final monthly statement for Non-Hourly Charges in excess of the foregoing cumulative total will be credited to those entities paying the FTR Surcharge in that final billing period.

III.8 Installed Capacity

III.8.1 ICAP Payments. From December 1, 2006 through May 31, 2010 (the "ICAP Transition Period"), each ICAP Resource (except for Dispatchable Asset Related Demand Resources) shall receive an ICAP Payment for each month that it is listed as an ICAP Resource and meeting the requirements applicable to the type of ICAP Resource as described in this Section III.8. An ICAP Resource not meeting the requirements applicable to the type of ICAP Resource as described in this Section III.8 will not receive ICAP Payments. Each ICAP Resource's ICAP Payment for a month will be calculated as the product of the resource's UCAP Rating and the fixed amount listed below ("ICAP Transition Rate"):

December 1, 2006 to May 31, 2007	$3.05/kW-month;
June 1, 2007 to May 31, 2008	$3.05/kW-month;
June 1, 2008 to May 31, 2009	$3.75/kW-month;
June 1, 2009 to May 31, 2010	$4.10/kW-month.

The ICAP Transition Rate shall not be adjusted during the ICAP Transition Period. Dispatchable Asset Related Demand Resources will not receive ICAP Payments, but instead each Dispatchable Asset Related Demand Resource will receive an adjustment to its share of ICAP Payment costs that is based on its ability to reduce consumption, as discussed in Section III.8.9.1. ICAP Payments will be billed and credited in the month subsequent to the Obligation Month. Netting of ICAP Payments against certain other sources of revenue, including Reliability Agreements and payments in the Forward Reserve Market, are addressed in the sections of this Market Rule providing for those sources of revenue.

III.8.2 ICAP Commitment Periods. The summer ICAP Commitment Period shall comprise the months of May through October; the winter ICAP Commitment Period shall comprise the months of November through April. To be eligible to receive ICAP Payments (or in the case of a Dispatchable Asset Related Demand Resource, to be eligible to receive an adjustment to its share of ICAP Payment costs), an ICAP Resource must be listed as an ICAP Resource for the entire duration of the relevant ICAP Commitment Period, except for ICAP Import Contracts, which must be at least two consecutive months in duration, with both months within the same ICAP Commitment Period. A resource that was not released for commercial operation at the beginning of an ICAP Commitment Period may receive ICAP Payments beginning with the first full calendar month of commercial operation, provided that before the first day of that month, the resource has established its Seasonal Claimed Capability with the ISO. A resource that was not in commercial operation at the beginning of an ICAP Commitment Period that begins receiving ICAP Payments during that ICAP Commitment Period must remain listed as an ICAP Resource for the remainder of the ICAP Commitment Period.

III.8.3 ICAP Resources. To receive ICAP Payments for a month (or in the case of a Dispatchable Asset Related Demand Resource, to receive an adjustment to its share of ICAP Payment costs), an ICAP Resource must satisfy the requirements and obligations associated with its resource type listed below.

III.8.3.1 Generating Units. References in this Section III.8 to "generating units" shall apply only to those generating units that are not designated as another type of ICAP Resource. To perform as an ICAP Resource, a generating unit in the New England Control Area must:

(a) each day, either Self-Schedule or submit a Supply Offer for each hour of the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule, unless and to the extent the generating unit is unable to do so due to an outage as defined in the ISO New England Manuals or due to temperature related de-ratings;

(b) submit Offer Data that specifies an Economic Maximum Limit;

(c) notify the ISO of any outage (including partial outages) and the expected return date from the outage;

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

(e) abide by the ISO maintenance coordination procedures;

(f) submit GADS Data to the ISO each month in accordance with the ISO New England Manuals;

(g) provide information reasonably requested by the ISO, including the name and location of the generating unit providing the Installed Capacity; and

(h) comply with the ISO New England Manuals.

III.8.3.2 Dispatchable Asset Related Demand Resources. External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demand Resources. To perform as an ICAP Resource, a Dispatchable Asset Related Demand Resource in the New England Control Area must:

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

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

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

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

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

(f) abide by the ISO maintenance coordination procedures;

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

(h) comply with the ISO New England Manuals.

1

III.8.3.3 Limited Energy Resources. To perform as an ICAP Resource, a Limited Energy Resource in the New England Control Area must:

(a) submit GADS Data to the ISO each month in accordance with the ISO New England Manuals;

(b) offer an Economic Maximum Limit, designating desired operating limits; and

(c) offer or Self-Schedule its Installed Capacity Equivalent into the Day-Ahead Energy Market each day and provide the energy equivalent of the Unforced Capacity in accordance with the rating process set forth in the ISO New England Manuals. Limited Energy Resources that are not scheduled in the Day-Ahead Energy Market to operate at a level above their bid-in Economic Maximum Limit may be called in Real-Time pursuant to a manual intervention by ISO dispatchers, who will account for the fact that the Limited Energy Resource may not be capable of responding;

(d) notify the ISO of any outage (including partial outages) and the expected return date from the outage;

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

(f) abide by the ISO maintenance coordination procedures;

(g) provide information reasonably requested by the ISO, including the name and location of the generating unit providing the Installed Capacity; and

(h) comply with the ISO New England Manuals.

III.8.3.4 Intermittent Power Resources. References in this Section III.8 to "Intermittent Power Resources" shall include, but is not limited to, Non-Dispatchable Qualifying Facilities. An Intermittent Power Resource may qualify as an ICAP Resource without having to comply with specific daily bidding and scheduling requirements, but must:

(a) submit Real-Time Offer Data that specifies an Economic Maximum Limit;

(b) notify the ISO of any outage (including partial outages) and the expected return date from the outage;

(c) in accordance with the ISO New England Manuals, perform Installed Capacity audit tests and submit the results to the ISO, or provide to the ISO alternative data as specified in the ISO New England Manuals;

(d) abide by the ISO maintenance coordination procedures;

(e) submit GADS Data or data equivalent to GADS Data to the ISO each month in accordance with the ISO New England Manuals;

(f) provide information reasonably requested by the ISO, including the name and location of the generating unit providing the Installed Capacity; and

(g) comply with the ISO New England Manuals.

For purposes of allocating system NCPC charges, an Intermittent Power Resource is not charged for a deviation between Day-Ahead and Real-Time schedules.

III.8.3.5 Settlement Only Resources. A Settlement Only Resource may qualify as an ICAP Resource without having to comply with specific daily bidding and scheduling requirements, but must:

(a) if choosing to have its UCAP Rating based on the Resource-specific EFORd per Section III.8.8.4 of this Market Rule, submit GADS Data to the ISO each month in accordance with the ISO New England Manuals; and

(b) in accordance with the ISO New England Manuals, perform Installed Capacity audit tests and submit the results to the ISO, or provide to the ISO appropriate historical production data.

III.8.3.6 Demand Resources.

III.8.3.6.1 Real-Time Demand Response Resources. During the ICAP Transition Period, the status of Demand Resources in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program as ICAP Resources shall be governed by the provisions of Appendix E (or its successor) to this Market Rule 1 and the ISO New England Manual M-LRP (Load Response Program). All such Resources that are ICAP Resources pursuant to Appendix E (or its successor) to this Market Rule 1 and the ISO New England Manual M-LRP

(Load Response Program) will receive ICAP Payments during the ICAP Transition Period.

III.8.3.6.2 Other Demand Resources. Other Demand Resources ("ODR") are installations undertaken as part of merchant, utility, or state-sponsored programs, and may include Energy Efficiency, Load Management, and Distributed Generation projects, as defined below, that are installed after June 16, 2006, and that result in additional and verifiable reductions in end-use customer demand on the electricity network in the New England Control Area during ODR Performance Hours. The minimum demand reduction for each ODR will be 100 kW aggregated within a single Load Zone. ODRs must comply with the timelines and deadlines associated with registration, reporting, and submission of ODR Measurement and Verification Plans set forth in this Section III.8.3.6.2 and in the ISO New England Manuals. ODRs meeting these definitions and criteria will be ICAP Resources subject to ISO review of the verification process described below.

III.8.3.6.2.1 Types of ODRs.

III.8.3.6.2.1.1 Energy Efficiency. Energy Efficiency shall mean installed measures and/or systems on end-use customer facilities that reduce the total amount of electrical energy and capacity that would otherwise have been needed to deliver an equivalent or improved level of end-use service. Such measures or systems include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, and industrial process equipment.

III.8.3.6.2.1.2 Load Management. Load Management shall mean installed measures, systems, and/or strategies on existing end-use customer facilities that curtail electrical usage or shift electrical usage from ODR Performance Hours to other hours and reduce the amount of capacity needed to deliver an equivalent or acceptable level of service at those end-use customer facilities. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, chilled water storage and other forms of electricity storage. Load Management does not include measures, systems and/or strategies that participate in either the Real-Time Demand Response Program (30-Minute and 2-Hour) or in the Real-Time Profiled Response Program.

III.8.3.6.2.1.3 Distributed Generation. Distributed Generation shall mean generation resources directly connected to end-use customer load and located behind the end-use customer's billing meter, which reduce the amount of energy and capacity that would otherwise have been drawn from the electricity network in the New England Control Area, provided that the capacity of the generation resource registered with the ISO does not exceed 5

MW, or does not exceed the most recent annual non-coincident peak demand of the individual end-use metered customer to which the generation resource is directly connected, whichever is greater.

III.8.3.6.2.2 Measurement, Verification, and Review of ODRs.

ODR Measurement and Verification Plans must be approved before the start of the month for which ICAP Payments will be received.

(a) ODR projects will require an ODR Measurement and Verification Plan in accordance with the ISO New England Load Response Program Manual or as set out in this Section III.8.3.6.2.2 to demonstrate reductions in end-use customer demand on the electricity network in the New England Control Area coincident with ODR Performance Hours. All ODR Measurement and Verification Plans must be consistent with the International Performance and Measurement Verification Protocol (http://www. ipmvp. org/), or an alternative protocol that has been reviewed and approved by the appropriate state regulatory agency with jurisdiction over utility or state-sponsored ODR programs. ODR Measurement and Verification Plans must demonstrate both availability and performance of ODRs in reducing load coincident with ODR Performance Hours. Distributed Generation ODRs must include individual metering or a metering protocol consistent with the International Performance and Measurement Verification Protocol and the ISO New England Load Response

Program Manual to monitor and verify generator output during ODR Performance Hours. The ODR Measurement and Verification Plans must include protocols for determining post-installation demand savings coincident with ODR Performance Hours and must compute monthly savings achieved by the ODRs coincident with ODR Performance Hours. Such ODR Measurement and Verification Plans must affirm that the siting, interconnection, and operation of the ODR complies with all applicable utility interconnection, and Federal, state, and local requirements. The ODR Measurement and Verification Plans must contain a projection of the ODR's monthly Demand Reduction Value over the ICAP Transition Period. ODR providers will submit no less frequently than once per year, a statement certifying that the ODR projects for which it is requesting compensation continue to perform in accordance with the ISO- or state-approved ODR Measurement and Verification Plans. The costs associated with measurement and verification shall be borne by the ODR supplier.

(b) Merchant suppliers of ODR projects are required to submit to the ISO detailed ODR Measurement and Verification Plans. The ISO will review and approve such ODR Measurement and Verification Plans. The ISO shall consider whether such ODR Measurement and Verification Plans use assumptions or methodologies consistent with a pre-approved state or utility ODR program in its review of the ODR Measurement and Verification Plans of merchant suppliers. The ODR Measurement and Verification Plans must include protocols for independent evaluation of reported demand savings. The ISO will review, ascertain necessary modifications, or approve such ODR Measurement and Verification Plans within 15 business days of submission.

(c) All other ODR providers (utility or state-sponsored) that operate programs under the review of state public utility commissions will submit ODR Measurement and Verification Plans to the ISO for review and comment, as appropriate. State-approved ODR Measurement and Verification Plans shall be assumed to have an adequate independent review process. If ISO review identifies possible concerns, the ISO will consult with the New England states to resolve the concern. Notwithstanding this consultation process, ODR Measurement and Verification Plans submitted pursuant to this subsection are not subject to ISO approval, with the exception of projects for which the ISO must approve the Critical Peak Hours across which Average Hourly Load Reductions would be computed. For the purpose of this subsection, ODR Measurement and Verification Plans include, but are not limited to, ODR Measurement and Verification Plans adopted or approved by state public utility commissions and utility ODR provider annual reports, technical manuals and ODR Measurement and Verification Plans reviewed by the state public utility commission with jurisdiction over the ODR utility provider.

III.8.3.6.2.3 Registration With ISO New England. Entities applying for ICAP Payments as a supplier of ODRs must be registered with the ISO. ODR-Only Customers must satisfy any applicable financial assurance criteria and pay an annual service fee of $500. End User Participants that participate as Governance-Only Members and wish to be paid as a supplier of ODRs must satisfy any applicable financial assurance criteria. The service fee will be applied to the ISO's expenses.

III.8.3.6.2.4 ODR Reporting. All suppliers of ODR resources shall submit monthly reports directly to the ISO. Such monthly reports will document the supplier's eligible pre-existing measures and new measures, and the supplier's total UCAP Rating from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly reports shall be based on their ODR Measurement and Verification Plans reviewed and/or approved in accordance with Section III.8.3.6.2.2 of this Market Rule 1 and will be the basis for monthly settlement with suppliers of ODRs. The monthly reports shall conform in all respects to the ISO's specifications with respect to content, format, and delivery methodology. The ISO will provide on a monthly basis the capacity value (MW) and total amount of ICAP Payments made to ODRs during the ICAP Transition Period on at least a Load Zone basis.

III.8.3.7 ICAP Import Contracts

III.8.3.7.1 General Requirements. An ICAP Import Contract must be at least two consecutive months in duration, with both months within the same ICAP Commitment Period. For an ICAP Import Contract to perform as an ICAP Resource, the Market Participant submitting the ICAP Import Contract must:

(a) register in accordance with the process described in the ISO New England Manuals;

(b) provide information reasonably requested by the ISO, including the name and location of the resource or resources providing the Installed Capacity;

(c) each day, either Self-Schedule or submit a competitively priced Supply Offer for the Installed Capacity Equivalent of the UCAP value given to the ICAP Import Contract for each hour of the Day-Ahead Energy Market and Real-Time Energy Market as described in Section III.1.10.1A and Section III.1.10.5 of this Market Rule, unless and to the extent the generating unit is unable to do so due to an outage as defined in the ISO New England Manuals or due to temperature related de-ratings (Market Participants receiving Hydro Quebec Interconnection Capability Credits, however, are not required to submit a Supply Offer or Self-Schedule for the energy equivalent of the credits);

(d) notify the ISO of any outage (including partial outages) and the expected return date from the outage;

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

(f) comply with the maintenance coordination procedures applicable to installed capacity resources in the external Control Area;

(g) provide data as described in Section III.8.8.6 of this market rule to allow for UCAP Ratings calculations;

(h) comply with the ISO New England Manuals.

III.8.3.7.2 ICAP Import Contract Performance. An ICAP Import Contract represents a commitment by the submitting party to offer and supply firm energy to the ISO-NE Control Area from resources located in an external Control Area. Depending upon the type of resource backing the ICAP Import Contract, the specific offer requirements are described below:

III.8.3.7.2.1 Energy Offer Requirements for ICAP Import Contracts by Resource Type. In addition to the provisions above, an ICAP Import Contract must perform as an ICAP Resource both in the Day-Ahead Energy Market and Real-Time Energy Market in one of the following ways, and must meet the additional associated requirements:

(a) *Priced external energy backed by an External Resource:* Energy must be offered through an External Transaction every day in the month and must cover every hour within each day.

(b) *Self-Scheduled external energy backed by an External Resource:* Energy must be scheduled through an External Transaction a minimum of 16 on-peak hours during week days that are not NERC holidays or as specified in the ISO New England Manuals.

(c) *Self-Scheduled external energy backed by a Control Area:* Energy must be scheduled through an External Transaction a minimum of 16 on-peak hours during week days that are not NERC holidays or as specified in the ISO New England Manuals. For an energy contract backed by a Control Area to qualify as an ICAP Resource, the Control Area shall afford the contract the same curtailment priority as that Control Area's native load.

(d) *Priced External energy backed by a Control Area:* Energy must be offered through an External Transaction every day in the month and must cover every hour within each day. For an energy contract backed by a Control Area to qualify as an ICAP Resource, the Control Area shall afford the contract the same curtailment priority as that Control Area's native load.

(e) Any number of individual energy transactions with a price and backed by an External Resource or backed by a Control Area may be submitted to support an ICAP Import Contract for an Operating Day, as long as the aggregate amount results in a submission for every hour of the day equal to the UCAP value of the ICAP Import Contract. Any number of individual Self-Scheduled energy transactions backed by an External Resource or backed by a Control Area may be submitted to support an ICAP Import Contract for an Operating Day, so long as the aggregate amount results in a submission for every required hour of the day, pursuant to Section III.8.3.7.2.1(c), equal to the UCAP value of the ICAP Import Contract. An individual ICAP Import Contract must be supported by energy transactions of the same resource type (priced or Self-Scheduled) for the entire month.

(f) *Hydro Quebec Interconnection Capability Credits backed by either an emergency interchange agreement or other emergency supply arrangement between the New England Control Area and the Hydro Quebec Control Area over the Phase I/II HVDC-TF:* During the ICAP Transition Period, the total transfer limit of the Phase I/II HVDC-TF interconnection with Hydro-Quebec shall be fixed at 1800 MW for UCAP purposes. The total MW of Hydro Quebec Interconnection Capability Credits shall be fixed at 1200

MW from March through November and at zero MW from December through February, and shall not receive an ICAP Payment for any month that is fixed at zero MW pursuant to Section III.8.1. The method for determining availability and capacity for Hydro Quebec Interconnection Capability Credits, as further detailed in the ISO New England Manuals, shall not change until after the ICAP Transition Period.

The remaining 600 MW of transfer capability over the Phase I/II HVDC-TF interconnection may be used for UCAP by any Market Participant that secures import rights and properly submits an ICAP Import Contract over the interconnection to the Day-Ahead Energy Market and Real-Time Energy Markets without causing reductions in the Hydro Quebec Interconnection Capability Credits. UCAP above 600 MW may be submitted as an ICAP Import Contract only in those months when the Hydro Quebec Interconnection Capability Credits are 1200 MW and the corresponding transmission reservation will result in a like reduction in the total Hydro Quebec Interconnection Capability Credits available for the holders of those credits. Only the remaining Hydro Quebec Interconnection Capability Credits will receive ICAP Payments. ICAP Import Contracts over the Phase I/II HVDC-TF interconnection with Hydro-Quebec that are properly submitted in the New England Market in accordance with this Market Rule and the ISO New England Manuals shall receive ICAP Payments and are subject to failure to deliver and failure to offer penalties as detailed in section III. 8.3.7.3.

(g) The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements:

(1) For imports crossing a single intervening Control Area, the Market Participant entering the ICAP Import Contract shall demonstrate that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the ICAP Import Contract, and that the energy export to the New England Control Area will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing.

(2) For imports crossing more than one intervening Control Area, in addition to the requirements above, the Market Participant entering the ICAP Import Contract shall demonstrate that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load.

III.8.3.7.2.2 Energy Offer Requirements Applicable to All ICAP Import Contracts: Regardless of the type of resource backing the ICAP Import Contract, energy transactions submitted in support of an ICAP Import Contract shall also comply with the following conditions:

(a) The Market Participant submitting each energy transaction shall include the contract identification number of the ICAP Import Contract it is intended to support so the two can be linked in the ISO's systems.

(b) The Market Participant submitting an ICAP Import Contract to the Day-Ahead Energy Market, for either unit or Control Area backed ICAP, is required to submit an energy transaction(s) in an amount (MW) equal to the ICAP value of the ICAP Import Contract being submitted. For unit-backed ICAP Import Contracts, the ICAP value shall reflect the temperature-adjusted SCC (or equivalent concept in the exporting Control Area) of the unit backing the contract. For any hour of any day that the ICAP Resource (the unit) cannot provide the full amount of temperature-adjusted rated capacity due to a maintenance or forced outage, the supplier must notify the ISO Operations Department.

(c) Submittal of energy transactions to the Day-Ahead Energy Market in support of an ICAP Import Contract requires submittal of matching energy transactions to the Real-Time Energy Market. The energy transactions submitted to the Real-Time Energy Market must match the energy transactions submitted to the Day-Ahead Energy Market subject to the right to submit different prices into the Real-Time Energy Market.

(d) Self-Scheduled energy transactions backed by an External Resource or backed by a Control Area and priced energy transactions that are backed by an External Resource or backed by a Control Area supporting an ICAP Import Contract, submitted to the Real-Time Energy Market, must be submitted prior to noon the day before the Operating Day in which they are intended to be scheduled. Self-Scheduled energy transactions backed by an External Resource or backed by a Control Area must pass "check out" with the neighboring Control Area during the day prior to the Operating Day. The requirements for an energy transaction to pass "check out" are described in the ISO New England Operating Procedures. Transactions with a price for energy and backed by an External Resource or backed by a Control Area in support of an ICAP Import Contract are not required to pass "check out" with the neighboring Control Area during the day prior to the Operating Day but are required to pass "check out" in Real-Time in accordance with the provisions of the ISO New England Operating Procedures.

(e) The Market Participant entering priced or Self-Scheduled energy transactions backed by an External Resource or backed by a Control Area to the Real-Time Energy Market in support of an ICAP Import Contract is responsible for making any and all transmission arrangements needed for the transaction, and is also responsible for submitting Supply Offers, in both the ISO system and the external Control Area, in such a manner that the energy associated with the ICAP Import Contract could actually be delivered when requested in Real-Time. Submissions of energy transactions shall include specific information as set forth in ISO New England Manual 11.

(f) A Market Participant with a priced energy transaction backed by an External Resource or backed by a Control Area supporting an ICAP Import Contract must submit the associated transmission service reservations, if required, and a valid NERC E-Tag to the Real-Time Energy Market no later than one hour before the Operating Hour in order to be eligible for scheduling in the Real-Time Energy Market. For Phase I/II HVDC-TF, the option to link transmission reservations and a valid NERC E-Tag is only applicable to those priced External Transactions associated with the transfer capability remaining after accounting for the Hydro Quebec Interconnection Capability Credits (HQ Interconnection Excess); for all other transactions over the interconnection, the reservation and E-Tag must be linked at the time of the Real-Time Energy Market submission.

(g) The “check-out” process described in the ISO New England Operating Procedures may require submission of energy transactions backed by External Resources to both the Day-Ahead Energy Market and Real-Time Market in the external Control Area, as well as evidence that the external Control Area will not cut the energy export to the New England Control Area so long as the underlying External Resource is energy in the external Control Area.

(h) Associated energy transactions must be submitted to cover the entire two-month minimum period according to resource type pursuant to Section 8.3.7.2.

(i) Associated priced energy transactions must be offered for each hour at a price that is at or below the final competitive offer level associated with the external interface. The final competitive offer level is the maximum of a historic daily *ex ante* competitive offer level or the hourly *ex post* competitive offer level determined for each external interface.

The single daily *ex ante* competitive offer level applies to each hour of the Operating Day. The *ex ante* competitive offer level is equal to the 99th percentile of the fuel-adjusted prices in the neighboring Control Area or at New England’s external proxy node, as determined in Section III.8.3.7.2.2 (i)(1), during the peak hours in which the New England Control Area was a net importer over the applicable external interface. The *ex ante* competitive offer level is calculated using a rolling 30-day period of historic price data. If the New England Control Area was not a net importer over the applicable external interface for any peak hour during the relevant 30-day period, prices will be selected from all peak hours. The fuel adjusted price for each historic hour is the Real-Time Energy Market price for the interface as determined in Section III.8.3.7.2.2(i)(1) multiplied by the ratio of the natural gas index price for the Offer Day and the natural gas index price for each day of the 30-day period of historic price data. The natural gas index price is the average of three natural gas pricing points in Massachusetts as reported by the natural gas price provider used by the INTMMU, except that for energy transactions over the New York interfaces the natural gas index price is the TRANSCO-Z6(NY) pricing point.

The *ex post* hourly competitive offer levels for the Operating Day are determined by the actual hourly prices during the Operating Day in the neighboring Control Area or at the New England Control Area's external proxy node as set forth in Section III.8.3.7.2.2 (i)(2).

(1) The source of the prices used to calculate the *ex ante* competitive offer levels for the applicable external interfaces is:

(a) For any energy transactions from the New York Control Area, the price used to calculate the *ex ante* competitive offer level is the New York hourly real-time energy price (NYISO Location-Based Marginal Price) at the source interface. A separate *ex ante* competitive offer level is calculated for each NYISO interface over which the energy is being delivered.

(b) For any energy transactions from the New Brunswick Control Area, the price used to calculate the *ex ante* competitive offer level is the New England hourly Real-Time LMP at the sink node (.I.SALBRYNB345 1).

(c) For any energy transactions from the Quebec Control Area, the price used to calculate the *ex ante* competitive offer level, whether the transaction is offered over the Phase I/II HVDC-TF or the Highgate interface, is: (i) the New England hourly Real-Time LMP at the Phase I/II HV-DC sink node (.I. HQ_P1_P2345 5); or (ii) the New England hourly Real-Time LMP at the Highgate sink node (.I.HQHIGHGATE120 2), whichever is higher after determining the 99th percentile of the fuel adjusted prices at those nodes.

(2) The source of the *ex post* prices used to calculate the competitive offer levels for the applicable interfaces is:

(a) For any energy transactions from the New York Control Area, the price used to calculate the *ex post* competitive offer level is the maximum of the New York hourly day-ahead energy price or the New York hourly real-time energy price (NYISO Location-Based Marginal Price) at the source interface. A separate *ex post* competitive offer level is calculated for each NYISO interface over which the energy is being delivered.

(b) For any energy transactions from the New Brunswick Control Area, the price used to calculate the *ex post* competitive offer level is the New England hourly Real-Time LMP at the sink node (.I.SALBRYNB345 1).

(c) For any energy transactions from the Quebec Control Area, the price used to calculate the *ex post* competitive offer level, whether the transaction is offered over the Phase I/II HVDC-TF or the Highgate interface, is the maximum of the following: (i) the New England hourly Real-Time LMP at the Phase I/II HV-DC sink node (.I. HQ_P1_P2345 5); (ii) the New England hourly Real-Time LMP at the Highgate sink node (.I.HQHIGHGATE120 2); (iii) the New York hourly Real-Time Location-Based Marginal Price at the sink node between the New York Control Area and the Quebec Control Area (HQ_LOAD_EXPORT); or (iv) the New York hourly day-ahead energy price at the sink node between the New York Control Area and the Quebec Control Area (HQ_LOAD_EXPORT).

III.8.3.7.3 Failure of ICAP Import Contract to Offer or Deliver.

III.8.3.7.3.1 Market Rule 1 provides for the imposition of penalties for failure to offer and deliver energy as required under the energy transactions supporting an ICAP Import Contract. This standard will reflect the availability characteristics of the Resource backing the ICAP Import Contract. An ICAP Import Contract that fails to meet the applicable delivery standard in any month will be subject to penalty. The specific application of the delivery standard as well as application of penalties for failure to offer are discussed below.

III.8.3.7.3.1.1 Penalties Applicable to ICAP Import Contracts for Failing to Offer Energy Transactions. A Market Participant requesting UCAP credit for an ICAP Import Contract is required to submit an energy transaction(s) in an amount (MW) that totals the ICAP value of the transaction into both the Day-Ahead Energy Market and Real-Time Energy Market as detailed in Market Rule Section III.8 and Manual 20. Energy transactions entered into by the Market Participant in support of the ICAP Import Contract must total the ICAP value of the ICAP Import Contract for each required hour of the month in both the Day-Ahead Energy Market and Real-Time Energy Market. Priced energy transactions must be offered at or below the final competitive offer level. Energy transactions requiring corresponding transmission reservations at the time of the Real-Time Energy Market submission must include the required data in order to be a valid energy transaction offer.

In the event that any of the conditions in this Section 8.3.7.3.1.1 and the additional applicable offer conditions detailed in Section III.8.3.7 are violated for any hour of an Operating Day, the Market Participant entering the ICAP Import Contract will be assessed a failure to offer penalty equal to the UCAP value of the ICAP Import Contract times twice the ICAP Transition Rate in Section III.8.1 of Market Rule 1 pro-rated to a daily value. However, a failure to offer penalty will not be applied to a Market Participant for any hour in which a priced External Transaction supporting an ICAP Import Contract is above the competitive offer level, but for which the Market Participant delivers energy greater or equal to the energy quantity offered.

III.8.3.7.3.1.2 Penalties Applicable to ICAP Import Contracts For Failing to Deliver Energy Transactions.

The ISO will compare the hourly megawatt amount requested for delivery by the ISO for the transaction to the energy actually delivered under that energy transaction by the Market Participant in each required hour to calculate any hourly delivery shortfalls. This evaluation is applied for energy transactions backed by an External Resource or backed by a Control Area.

The following conditions will not result in a delivery shortfall:

(a) Market Participants with ICAP Import Contracts will not be assessed a failure to deliver penalty if an energy transaction backed by an External Resource or backed by a Control Area failed to check out the day before the Operating Day in the associated Control Area as described in Section III.8.3.7.2.2. A Market Participant will be assessed a failure to deliver penalty for failing to check out in Real-Time in the associated Control Area as described in Section III.8.3.7.2.2.

(b) Except during hours when the ISO declares system-wide OP4 event, if a priced energy transaction supporting an ICAP Import contract is associated with the New York Control Area and the Market Participant does not deliver energy to the New England Control Area when requested during hours that the Real-Time Energy Market price at the source location is higher than the Real-Time LMP at the associated New England Control Area external node, no delivery shortfall shall be assessed.

(c) If the applicable import ties are fully loaded such that a transaction that would otherwise be dispatched cannot flow, no delivery shortfall shall be assessed.

(d) The failure to deliver penalty will not apply to External Control Area backed Self-Scheduled energy transactions for which Unforced Capacity is derated in accordance with the process described in the ISO New England Manuals.

If a Market Participant does not link the transaction to the associated transmission reservation and NERC E-Tag in the Real-Time Energy Market for any hour during which the External Resource or Transaction would otherwise have been economically and reliably scheduled in the Real-Time Energy Market, a delivery shortfall shall be assessed.

Any hourly delivery shortfalls will be summed to develop a total delivery shortfall for the transaction for the month. In the event that the energy associated with an ICAP Import Contract is not delivered for any hour requested by the ISO, the Market Participant entering the ICAP Import Contract will be charged a failure to deliver penalty equal to the percentage of required hours without full delivery relative to required hours that energy was requested times the UCAP value of the ICAP Import Contract, times twice the ICAP Transition Rates in Section III.8.1. This delivery test is an hourly test. Delivery shortfalls in one hour cannot be made up by excess delivery in another hour. Any penalty revenues collected will be allocated in accordance with the allocation methodology outlined in Section 4 of ISO New England Manual 20.

III.8.3.7.3.1.3 Penalties Applicable to ICAP Import Contracts. In addition to the failure to offer penalty and the failure to deliver penalty, a Market Participant failing to comply with the cleared Day-Ahead schedule of the supporting energy transaction(s) will be responsible for a NCPC Charge for any Real-Time Generation Obligation Deviation created.

III.8.3.7.3.2 Penalty Limits. In a given Obligation Month, a Market Participant failing to schedule and also failing to deliver ICAP Import Contracts may be charged the sum of the applicable penalties. However, for a given Obligation Month, the sum of the scheduling and delivery penalties shall not exceed the total UCAP value of the ICAP Import Contract times twice the monthly ICAP Transition Rates.

III.8.3.7.3.3 Penalties under Resource-Like Treatment. If the Lead Market Participant for a long-term grandfathered ICAP Import Contract, listed in this Section III.8 and electing treatment as a Resource fails to submit an External Transaction for dispatchable energy backed by an External Resource or backed by a Control Area or for external non-dispatchable energy backed by an External Resource or backed by a Control Area in support of that ICAP Import Contract, the Lead Market Participant for that transaction may be assessed a scheduling penalty. Any ICAP Payment revenues collected will be allocated in accordance with the ISO New England Manuals.

For Lead Market Participants electing to have an eligible transaction(s) for external non-dispatchable energy backed by an External Resource or backed by a Control Area treated as a Resource, the ISO will apply an 80% delivery standard and monitor for compliance. With respect to delivery penalties, any monthly failure to meet delivery requirements will be treated as a forced outage for the purposes of calculating the UCAP value of the transaction, in place of the delivery deficiency penalty, and shall be reported as such by the Lead Market Participant for the transaction, subject to ISO review. A monthly failure will be utilized in Formula 1 (set forth in Section 3.5 of Manual

20) such that the percentage value of the total monthly delivery shortfall is used in place of the other hourly EFORd formula variables for that specific monthly time period. With respect to reporting of the hours outside the 5 by 16 delivery requirement for ICAP Import Contracts for external non-dispatchable energy backed by an External Resource or backed by a Control Area electing Resource-like treatment, these hours will be classified as reserve shutdown hours. Specifically, a 79% compliance would result in a 21% failure, where: Forced Outage Hours for a month = (% failure * 16 hrs/day * # of non-NERC Holiday weekdays/month), Service Hours for a month = (16 hrs/day * # of non-NERC Holiday weekdays/month) less Forced Outage Hours for that month, and all Forced Outage Hours are considered full, such that $f_{fgbe} = 1$ and $f_{pgbe} = 0$ within Formula 1. The Lead Market Participant shall provide to the ISO hourly delivery data for each month with the calculation of Forced Outage Hours, Service Hours, and Reserve Shutdown Hours to enable the ISO to perform the EFORd calculation for each month.

III.8.4 ICAP Resource Outage Scheduling Provisions.

III.8.4.1 Outage Rescheduling. For each ICAP Resource other than Settlement Only Resources, ICAP Import Contracts, and Demand Resources, Market Participants shall submit a confidential notification to the ISO of the ICAP Resource's proposed outage schedules in accordance with the ISO New England Manuals. Based upon a reliability assessment, if Operating Reserve deficiencies are projected to occur in certain weeks for the upcoming calendar year, the ISO will request voluntary re-scheduling of outages. For fully or partially listed ICAP Resources subject to this requirement, if voluntary re-scheduling is ineffective, the ISO will invoke forced rescheduling of outages to ensure that projected Operating Reserve over the upcoming year is adequate. A Market Participant that refuses a forced rescheduling of an outage for any fully or partially listed ICAP Resource subject to this requirement will be ineligible for ICAP Payments associated with that ICAP Resource during any month in which it undertakes such outages. The rescheduling process is described in the ISO New England Manuals.

III.8.4.2 Coordination with External Control Areas. In accordance with the ISO New England Manuals, the ISO shall coordinate outage schedules for External Resources with the external Control Area.

III.8.5 Additional Operating Data Provisions. With respect to the submission of GADS Data, data equivalent to GADS Data, or other Operating Data in accordance with the provisions above and the ISO New England Manuals:

III.8.5.1 Calculation of EFORd. In its calculation of EFORd, the ISO shall deem an ICAP Resource to be completely forced out for each month for which the Market Participant has not submitted full GADS Data, data equivalent to GADS Data, or other Operating Data, as appropriate. For an ICAP Resource that has been deemed completely forced out for a particular month, the Market Participant may submit new Operating Data for that month to the ISO at any time. The ISO will use such new Operating Data, if received in a timely manner, when calculating EFORd for the

ICAP Resource. Upon a showing of extraordinary circumstances, the ISO retains the discretion to accept at any time Operating Data which have not been submitted in a timely manner, or which do not fully conform with the ISO New England Manuals.

III.8.5.2 Sanctions Regarding Operating Data. Market Participants that do not submit full GADS Data, data equivalent to GADS Data, or other Operating Data, as appropriate, may be subject to the sanctions provided in Appendix B of this Market Rule.

III.8.6 Sanctions. Any ICAP Resource that fails on a daily basis to meet its requirements under this Section III.8 may be subject to sanctions pursuant to Appendix B of this Market Rule. If an entity other than the owner of the ICAP Resource that is providing Unforced Capacity is responsible for fulfilling submission of Supply Offer or Demand Bid data, scheduling, and notification requirements, the owner and that entity must designate to the ISO which of them will be responsible for complying with the scheduling, Supply Offer or Demand bid data submission, and notification requirements. The designated entity shall be subject to sanctions pursuant to Appendix B of this Market Rule.

III.8.7 De-Listing. ICAP Resources other than Dispatchable Asset Related Demand Resources may de-list in accordance with the provisions in this Section III.8.7. Dispatchable Asset Related Demand Resources are not eligible to de-list.

III.8.7.1 De-Listing and Listing Timing and Notification. The Lead Market Participant for an ICAP Resource must notify the ISO in accordance with the dates specified below of any Unforced Capacity it wishes to fully or partially de-list as an ICAP Resource. An ICAP Resource unit, or part thereof, may be de-listed by notifying the ISO in the manner specified in the ISO New England Manuals at any time prior to 1800 hours of a day that is at least two full business days prior to the start of the first ICAP Commitment Period for which the unit wishes to de-list. Once a unit, or part thereof, de-lists, it remains de-listed until a listing notification is made in accordance with ISO New England Manual 20. A notification to list must also be made prior to 1800 hours of a day that is at least two full business days prior to the start of the ICAP Commitment Period for which the unit wishes to list. All de-listing and listing actions shall be effective as of the first day of the relevant ICAP Commitment Period. A timely de-listing or listing notification shall be binding for the duration of the relevant ICAP Commitment Period(s) with respect to the calculation of UCAP Ratings and ICAP Payments.

III.8.7.2 Rights and Obligations of De-Listed Resources.

(a) If not fully de-listed, a Resource may only be split into a single listed and a single de-listed segment. Resources shall only be de-listed in whole MW increments.

(b) To the extent that it is de-listed, Unforced Capacity may be sold as a capacity-based product for use in an external Control Area and/or the Resource may operate as an energy-only Resource.

(c) In the event that a Resource is fully or partially de-listed, the owner of the Resource is not excused from the requirement to offer energy from the Resource to the Real-Time Energy Market if the Resource is available.

(d) Energy from fully de-listed Resources may be offered to the New England Control Area in the Day-Ahead Energy Market and/or the Real-Time Energy Market, although the Energy may be offered to an external Control Area.

(e) Any partially de-listed Resource shall offer its full capability to both the New England Day-Ahead Energy Market and the Real-Time Energy Market, although the Energy may be offered to an external Control Area.

(f) A fully or partially de-listed resource may sell non-recallable energy, up to the quantity of capacity that is de-listed, for use in another Control Area. These non-recallable energy transactions are subject to additional requirements, listed below, regarding the availability of the resource backing the transaction that will be reviewed when the New England Control Area is under ISO New England Operating Procedure 4 (Action During a Capacity Deficiency) conditions. These requirements are: (i) the partially or fully de-listed resource must be self-scheduled to a MW level equal to or greater than the amount of the non-recallable transaction, and (ii) a de-rate of a partially de-listed Resource backing the sale to less than its Seasonal Claimed Capability shall be allocated pro-rata between the listed and de-listed parts of the Resource. Upon meeting these requirements, a non-recallable energy transaction cannot be curtailed due to system wide capacity deficient conditions in the New England Control Area.

III.8.7.3 De-Listed Resource Outage Provisions.

(a) Market Participants must submit proposed outage schedules for fully and partially de-listed Resources in accordance with the ISO New England Manuals. Outage requests for de-listed Resources shall not be subject to forced rescheduling by the ISO.

(b) Any outage while fully or partially de-listed shall be accurately accounted for in accordance with NERC GADS procedures and the ISO New England Manuals in the event that the unit is re-listed as an ICAP Resource.

(c) In the event that the ISO determines that a proposed outage of a de-listed Resource would result in a violation of reliability criteria in accordance with ISO operating procedures, and that no other action, including forced rescheduling of ICAP Resource outages will resolve the reliability issue, the ISO may request additional capacity from the de-listed Resource (to be provided on a voluntary basis) and any other Resource capable of reducing or eliminating the reliability criteria violation. Any de-listed Resource that responds to an ISO request and elects to reschedule its outage and become an ICAP Resource, which was not sold as capacity to New York shall be re-listed as an ICAP Resource, and all obligations associated with this status shall apply to the Resource for the remainder of the Obligation Month. In exchange for assuming this reliability obligation, the Resource is eligible to receive ICAP Payments in the Obligation Month for which the Resource has been re-listed, plus any additional reasonably incurred maintenance and opportunity type costs associated with re-scheduling the outage and becoming an ICAP Resource. At the end of the Obligation Month, the Resource may choose to return to de-listed status or to remain listed for the remainder of the ICAP Commitment Period subject to the provisions of this Section III.8. Any de-listed Resource which was sold as capacity to New York and that responds to an ISO request and elects to reschedule its outage shall be paid for reasonably incurred maintenance and opportunity type costs associated with re-scheduling the outage, but these Resources shall not receive associated ICAP Payments, since they have already received ICAP compensation from New York. Market Participants shall submit compensation applications to the ISO and shall provide supporting data and documents for any additional reasonably incurred maintenance and opportunity type costs. ICAP Payments shall be guaranteed upon application to the ISO, subject to verification that the Resource was de-listed and that an outage was rescheduled, and subject to the normal ISO settlement business processes and payment schedules. Payment of any additional reasonably incurred maintenance and opportunity type costs shall be subject to verification of the supporting data provided to substantiate the payment request. The cost of these payments shall be allocated to Market Participants in the same manner as ICAP Payment costs, as described in Section III.8.9 of this Market Rule.

III.8.8 UCAP Ratings. A UCAP Rating, in MW, will be determined for each ICAP Resource as described below.

III.8.8.1 Generating Unit UCAP Ratings. For each ICAP Resource that is a generating unit, the UCAP Rating will be calculated as the product of the ICAP Resource's Seasonal Claimed Capability in effect at the beginning of the Obligation Month multiplied by one minus the average of that ICAP Resource's EFORd scores for each of the previous two Capability Periods (each of which will comprise 50 percent of the EFORd portion of the UCAP Rating).

III.8.8.1.1 Calculation of Seasonal EFORd Scores. At the end of each Capability Period, an EFORd score shall be calculated for each generating unit ICAP Resource for that Capability Period based on EFORd scores for the months in that Capability Period. In months in which the generating unit is de-listed, unweighted EFORd shall apply. In months in which a portion of the generating unit is de-listed, unweighted EFORd shall apply to the de-listed portion and weighted EFORd shall apply to the listed portion. Where weighted EFORd is used, it will be determined based on the following hourly weightings:

Type of Hour	Definition	Weighting Factor
Off-Peak Hour	All hours that are not On-Peak hours.	0.0
On-Peak Hour	Hours-ending 8:00 a.m. through 11:00 p.m. on all non-NERC holiday weekdays.	1.0
Seasonal Peak Hour	The 200 hours pertaining to: • the highest 100 hourly system loads during the Summer Capability Period; and • the highest 100 hourly system loads during the Winter Capability Period.	20.0
Shortage Hour	Periods of system-wide OP4, Action 6 or 11 or OP7 implementation.	40.0

For any hour that falls into more than one of the categories described in the table above, the weighting factors shall not be additive; the hour will be assigned the highest single weighting factor among the applicable categories.

III.8.8.1.2 **Phase In.** The seasonal EFORd methodology will be phased in as follows:

(a) From December 2006 through May 2007, an ICAP Resource's EFORd score will be based on twelve-month rolling unweighted EFORd.

(b) From June 2007 through September 2007, an ICAP Resource's EFORd score will be calculated as 50 percent weighted EFORd from the period October 2006 through May 2007 and 50 percent unweighted EFORd from the period April 2006 through September 2006.

(c) After September 2007 and through the end of the ICAP Transition Period, an ICAP Resource's EFORd score that will be applied in a Capability Period will be calculated using that ICAP Resource's EFORd scores for each of the previous two Capability Periods, which will each comprise 50 percent of the EFORd score, as discussed above.

III.8.8.1.3 Effect of Certain Equipment Failures. When a Resource is forced into an outage by an equipment failure that involves equipment located on the high voltage side of the electric network beyond the step-up transformer, and including such step-up transformer, the outage will not be counted for purposes of calculating weighted and unweighted EFORd.

III.8.8.2 Limited Energy Resources UCAP Ratings. A Limited Energy Resource will have its UCAP Rating based on the Resource-specific EFORd, calculated in the same manner as for generating units specified in Section III.8.8.1.

III.8.8.3 Intermittent Power Resources UCAP Ratings. An Intermittent Power Resource may claim up to its Installed Capacity as Unforced Capacity in accordance with the rating procedures set forth in the ISO New England Manuals. In calculating the UCAP Rating for an Intermittent Power Resource, the resource's historical capacity factor will be adjusted to remove the effects of outages in accordance with the rating process described in the ISO New England Manuals. Throughout the ICAP Transition Period, Intermittent Power Resources shall continue to receive the treatment for determining capacity and availability in effect on June 16, 2006.

III.8.8.4 Settlement Only Resources UCAP Ratings. A Settlement Only Resource may choose to have its UCAP Rating based on the Resource-specific EFORd, calculated in the same manner as for generating units specified in Section III.8.8.1, or on its annual NERC class average EFORd rating, as more fully described in the ISO New England Manuals.

III.8.8.5 Demand Resources UCAP Ratings.

III.8.8.5.1 Real-Time Demand Response Resources. The UCAP Rating of a Resource in the Real-Time Demand Response Program (30-Minute and 2-Hour) or in the Real-Time Profiled Response Program will be equal to its Adjusted Capability multiplied by the Installed Capacity Requirement divided by the 50/50 system peak load forecast as determined by the ISO.

III.8.8.5.2 Other Demand Resources. The UCAP Rating of an ODR for a month shall be equal to its Capacity Value for the month as determined pursuant to Section III.8.8.5.2.1, multiplied by the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO.

III.8.8.5.2.1 ODR Capacity Values. The Capacity Value (in kW-month) of an ODR for a month will be equal to its Demand Reduction Value in that month multiplied by 1.08 to reflect an 8 percent average avoided peak transmission and distribution losses used by the Regional System Planning process in 2006. All Demand Reduction Values are based on reductions in end-use demand on the electricity network in the New England Control Area coincident with ODR Performance Hours. Summer ODR Performance Hours shall be defined as hours ending 1400 through 1700, Monday through Friday on non-holidays, or Critical Peak Hours during the months of June, July, and August. Winter ODR Performance Hours shall be defined as hours ending 1800 through 1900, Monday through Friday on non-holidays, or other specific Critical Peak Hours during the months of December and January. The ODR provider shall designate the specific methodology used to establish ODR Performance Hours, including the use of Critical Peak Hours, in its ODR Measurement and Verification Plan as per Section III.8.3.6.2.2 of this Market Rule. Once selected, the ODR provider may not change the option used to establish ODR Performance Hours. The Demand Reduction Value for each ODR type shall be established as follows:

(a) For Energy Efficiency, monthly Demand Reduction Values shall be established based on seasonal Demand Reduction Values. The summer Demand Reduction Value of Energy Efficiency shall be equal to its Average Hourly Load Reduction over summer ODR Performance Hours – *i.e.*, the total kWh saved by the ODR over summer ODR Performance Hours divided by the total number of summer ODR Performance Hours. This summer Demand Reduction Value will apply to the months of April through November. The winter Demand Reduction Value of Energy Efficiency shall be equal to its Average Hourly Load Reduction over winter ODR Performance Hours – *i.e.*, the total kWh saved by the ODR over winter ODR Performance Hours divided by the total number of winter ODR Performance Hours. This winter Demand Reduction Value will apply to the months of December through March. Should a new Energy Efficiency resource enter service at a time such that there is an incomplete set of performance data for summer or winter ODR Performance

Hours upon which to establish its Demand Reduction Value as described above, then the missing data shall be supplemented with engineering estimates or audit results. An Energy Efficiency resource provider will have the option of conducting an audit before the end of a month to establish its Demand Reduction Value for a subsequent month in which there are no Critical Peak Hours, provided that the audit results shall not supplant the seasonal Demand Reduction Value based on Critical Peak Hours for the season. Engineering estimates and the procedures for scheduling and conducting an audit must be submitted as part of the ODR Measurement and Verification Plan, which would be reviewed and approved, if appropriate as per Section III.8.3.6.2.2 of this Market Rule, by the ISO.

(b) For Load Management, monthly Demand Reduction Values shall be determined. For each month during the months of June, July, August, December and January, the Demand Reduction Value of Load Management shall be based on its Average Hourly Load Reduction during ODR Performance Hours for the month – *i.e.*, total kWh reduced during ODR Performance Hours in the month divided by total ODR Performance Hours in that month. For Load Management electing to use Critical Peak Hours to determine ODR Performance Hours, the Demand Reduction Value for September, October, November, April and May shall be based on (i) its Average Hourly Load Reduction across the most recent summer ODR Performance Hours if there are no Critical Peak Hours in the month or (ii) the simple average of (a) its Average Hourly Load Reduction across the most recent summer ODR Performance Hours and (b) its Average Hourly Load Reduction across the Critical Peak Hours in the month if there are Critical Peak Hours in the month. For Load Management not using Critical Peak Hours to determine ODR Performance Hours, the Demand Reduction Value for September, October, November, April and May shall be based on its Average Hourly Load Reduction across the most recent summer ODR Performance Hours. For Load Management electing to use Critical Peak Hours to determine ODR Performance Hours, the Demand Reduction Value for February and March shall be based on (i) its Average Hourly Load Reduction across the most recent winter ODR Performance Hours if there are no Critical Peak Hours in the month or (ii) the simple average of (a) its Average Hourly Load Reduction across the most recent winter ODR Performance Hours and (b) its Average Hourly Load Reduction across the Critical Peak Hours in the month if there are Critical Peak Hours in the month. For Load Management not using Critical Peak Hours to determine ODR Performance Hours, the Demand Reduction Value for February and March shall be based on its Average Hourly Load Reduction across the most recent winter ODR Performance Hours. Should a new Load Management resource enter service at a time such that there is an incomplete set of performance data for summer or winter ODR Performance Hours upon which to establish its

Demand Reduction Value as described above, then the missing data shall be supplemented with engineering estimates or audit results. A Load Management resource provider electing to use the Critical Peak Hours option will have the option of conducting an audit before the end of a month to establish its Demand Reduction Value for a subsequent month in which there are no Critical Peak Hours, provided that the audit results shall not supplant the seasonal Demand Reduction Value based on Critical Peak Hours for the season. Engineering estimates and the procedures for scheduling and conducting an audit must be submitted as part of the ODR Measurement and Verification Plan, which would be reviewed and approved, if appropriate as per Section III.8.3.6.2.2 of this Market Rule, by the ISO.

(c) For Distributed Generation, monthly Demand Reduction Values shall be determined. For each month during the months of June, July, August, December and January, the Demand Reduction Value of Distributed Generation shall be based on its Average Hourly Output during ODR Performance Hours for the month – *i.e.*, total kWh produced during ODR Performance Hours in the month divided by total ODR Performance Hours in that month. For Distributed Generation electing to use Critical Peak Hours to determine ODR Performance Hours, the Demand Reduction Value for September, October, November, April and May shall be based on (i) its Average Hourly Output across the most recent summer ODR

Performance Hours if there are no Critical Peak Hours in the month or (ii) the simple average of (a) its Average Hourly Output across the most recent summer ODR Performance Hours and (b) its Average Hourly Output across the Critical Peak Hours in the month if there are Critical Peak Hours in the month. For Distributed Generation not using Critical Peak Hours to determine ODR Performance Hours, the Demand Reduction Value for September, October, November, April and May shall be based on its Average Hourly Output across the most recent summer ODR Performance Hours. For Distributed Generation electing to use Critical Peak Hours to determine ODR Performance Hours, the Demand Reduction Value for February and March shall be based on (i) its Average Hourly Output across the most recent winter ODR Performance Hours if there are no Critical Peak Hours in the month or (ii) the simple average of (a) its Average Hourly Output across the most recent winter ODR Performance hours and (b) its Average Hourly Output across the Critical Peak Hours in the month if there are Critical Peak Hours in the month. For Distributed Generation not using Critical Peak Hours to determine ODR Performance Hours, the Demand Reduction Value for February and March shall be based on its Average Hourly Output across the most recent winter ODR Performance Hours. Should a new Distributed Generation resource enter service at a time such that there is an incomplete set of performance data for summer or winter ODR Performance

Hours upon which to establish its Demand Reduction Value as described above, then the missing data shall be supplemented with engineering estimates or audit results. A Distributed Generation resource provider electing to use the Critical Peak Hours option will have the option of conducting an audit before the end of a month to establish its Demand Reduction Value for a subsequent month in which there are no Critical Peak Hours, provided that the audit results shall not supplant the seasonal Demand Reduction Value based on Critical Peak Hours for the season. Engineering estimates and the procedures for scheduling and conducting an audit must be submitted as part of the ODR Measurement and Verification Plan, which would be reviewed and approved, if appropriate as per Section III.8.3.6.2.2 of this Market Rule, by the ISO.

III.8.8.6 ICAP Import Contracts UCAP Ratings. The Market Participant entering the ICAP Import Contract shall be responsible for supplying either the GADS Data, data equivalent to GADS Data, or other Operating Data to the ISO in accordance with the ISO New England Manuals necessary to calculate an EFORd for unit-backed ICAP Import Contracts, or for directly supplying the EFORd for the unit backing the ICAP Import Contract calculated in accordance with the formulas in the ISO New England Manuals, and subject to verification with the external Control Area where the unit is located. In the case of ICAP Import Contracts backed by an external Control Area, CARL Data shall be submitted in support of the ICAP Import Contract. The CARL Data shall be used to assess the ability of the external Control Area to deliver energy in support of the ICAP Import Contract and to calculate the EFORd of the ICAP Import Contract. The EFORd data shall be used to reduce the energy face value of the contract from an ICAP value to a UCAP Rating for the purposes of calculating ICAP Payments. The UCAP Rating of the contract is determined by multiplying the ICAP value of the contract by the quantity one minus the EFORd of the transaction, where the EFORd of the transaction is the rolling twelve month average EFORd of the external Control Area. Certain ICAP Import Contracts are afforded grandfathered status with special treatment that is described in the ISO New England Manuals. Those ICAP Import Contracts and their associated MW values are identified in the following table:

Contract Description	**Grandfathered (MW)**	**Contract End Date**
NYPA: NY – NE: CMEEC NYPA: NY – NE: MMWEC NYPA: NY – NE: Pascoag NYPA: NY – NE: VELCO	20.9 81.8 2.4 15.0 120.1	10/31/2003 10/31/2003 10/31/2003 10/31/2003
VJO: Highgate – NE VJO: Phase I/II – NE VJO: CCC Block Load	Up to 225* Up to 110* Up to 60*	2020
VPPSA NYSEG: NY-NE*	6 (April-Oct) 7 (Nov-March)	10/31/2003
BED NYSEG: NY – NE*	10	12/31/2009
Select: New Brunswick	224	2020

*The total grandfathered MW for the VJO contract are limited to 335 MW.

III.8.9 ICAP Payments Cost Allocation. Each month, each Market Participant shall be allocated a percentage of the total costs of ICAP Payments for that month that is equal to the Market Participant's pro rata share of the sum of all Market Participant annual coincident contributions to the New England annual peak load from the calendar year immediately prior to the Capability Year. Market Participants may meet their assigned obligations through use of bilateral contracts.

III.8.9.1 Calculation of Each Market Participant's Contribution to the New England Annual Coincident Peak Load. The ISO New England Manuals and ISO New England Administrative Procedures set forth the procedures for settlement data to be submitted to the ISO. A Market Participant's contribution to the New England annual coincident peak load from the calendar year immediately prior to the Capability Year shall be the sum of the annual coincident peak contributions from the prior calendar year of the customers served by the Market Participant at each Load Asset in all Load Zones coincident with the annual New England peak of the prior calendar year. Where a Market Participant's customer is a Dispatchable Asset Related Demand Resource, that customer's contribution to the Market Participant's total shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand Resource, adjusted to the extent necessary as follows:

(a) Dispatchable Asset Related Demand Resources are subject to Nominated Consumption Limit audits in accordance with the ISO New England Manuals. The Nominated

Consumption Limit value is subject to adjustment based on the results of such audits.

(b) The Nominated Consumption Limit value of each Dispatchable Asset Related Demand Resource is subject to adjustment for customer additions and deletions calculated pursuant to Section III.8.9.3 of this Market Rule.

(c) The Nominated Consumption Limit value of each Dispatchable Asset Related Demand Resource is subject to adjustment for non-conformance with the requirements listed in Section III.8.3.2 of this Market Rule and as further described in the ISO New England Manuals.

III.8.9.2 Exempt Load. The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts:

(a) Load associated with pumping of pumped hydro generators, if the resource was pumping;

(b) Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO for ICAP Resources and non-ICAP Resources as applicable; and

(c) Transmission losses associated with delivery of energy over the Control Area tie lines.

III.8.9.3 Load Shifting. The ISO shall account for load-shifting among Market Participants each month using the best available information provided to it and the affected Market Participants by the entities responsible for submitting settlement data in accordance with the ISO New England Manuals. Each month, as customers are gained and lost by Market Participants through load-shifting, the ISO will adjust the ICAP Payment costs allocated to each Market Participant accordingly. In addition, adjustments will be made to each Market Participant's allocation of ICAP Payment costs to account for customers entering and permanently leaving the New England Control Area. The net impact of customer entry and exit shall be proportionately allocated to Market Participants in accordance with the procedures in the ISO New England Manuals.

III.9 Forward Reserve Market

The Forward Reserve Market is a market to procure TMNSR and TMOR on a forward basis to satisfy forward TMNSR and TMOR requirements..

III.9.1 Forward Reserve Market Timing.

A Forward Reserve Auction will be held approximately two months in advance of each Forward Reserve Procurement Period. The Forward Reserve Auction input parameters and assumptions will be evaluated, published and reviewed with Market Participants prior to the Forward Reserve Auction.

The Forward Reserve Procurement Periods shall be the Winter Capability Period (October 1 through May 31) or the Summer Capability Period (June 1 through September 30), as applicable.

The Forward Reserve Delivery Period shall be hour ending 0800 through hour ending 2300 for each weekday of the Procurement Period excluding those weekdays that are defined as NERC holidays.

III.9.2 Forward Reserve Market Reserve Requirements. The ISO shall conduct an advance purchase of capability to satisfy the expected Forward Reserve requirements for the system and each Reserve Zone as calculated by the ISO in accordance with the following procedures and as specified more fully in the ISO New England Manuals and ISO New England Administrative Procedures. The Forward Reserve Market Reserve requirements will be specified as part of the Forward Reserve Auction parameters and will be published and reviewed with Market Participants prior to each Forward Reserve Auction.

III.9.2.1 Forward Reserve Market Minimum Reserve Requirements. The Forward Reserve Market minimum requirements for the New England Control Area will be based on the forecast of the first and second contingency supply losses for the next Forward Reserve Procurement Period and will consist of the following:

(i) One half of the forecasted first contingency supply loss will be specified as the minimum TMNSR to be purchased,

(ii) One half of the second contingency supply loss will be specified as the minimum TMOR to be purchased,

(iii) An amount of Replacement Reserve in the form of incremental TMOR will be specified in accordance with the Real-Time Replacement Reserve requirement as described in ISO New England Operating Procedure No. 8, Operating Reserve and Regulation and will be added to the minimum TMOR to be purchased.

The minimum requirements specified above, further adjusted to respect the additional provisions described in Sections III.9.2.2 and III.9.2.3 below, represents the set of requirements that will be input into the Forward Reserve Auction.

III.9.2.2 Minimum Reserve Purchase for "Rest of System"

The Rest of System is the part of the New England Control Area that does not have a locational Reserve requirement. In order to ensure sufficient distribution of Operating Reserves to meet most operational practices, the ISO shall evaluate the historical assignment of reserve Resources and shall determine a minimum "Rest of System" reserve requirement to be procured in the Forward Reserve Market. The "Rest of System" reserve requirement will be 600 MW.

III.9.2.3 Locational Reserve Requirements for Reserve Zones

Locational Reserve requirements will be established for each Reserve Zone. The locational reserve requirements will reflect the need for 30-minute contingency response to provide 2nd contingency protection for each import constrained Reserve Zone. The locational reserve requirements can be satisfied only by Resources that are located within a Reserve Zone and that are capable of providing 30-minute or higher quality reserve products.

The ISO shall establish the locational reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each Reserve Zone for like Forward Reserve Procurement Periods. The ISO will commence the analysis on February 1 or the first business day thereafter for the subsequent summer Forward Reserve Procurement Period and on June 1 or the first business day thereafter for the subsequent winter Forward Reserve Procurement Period.

These daily peak hour requirements will be aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each Reserve Zone will establish the locational requirement.

In the event of a change in the configuration of the transmission system or the addition, deactivation or retirement of a major generating Resource, the rolling two-year historical analysis will be calculated in a manner that reflects the change in configuration of the transmission system or the addition, deactivation or retirement of a major generating Resource as of the commencement date of the analysis provided that the following conditions are met:

(a) Change in Configuration of the Transmission System

Any change in the configuration of the transmission system must have been placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the Locational Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the Locational Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

If the change in the configuration of the transmission ystem consists of a new facility or upgrade of an existing facility, the facility must have operated at an availability level of at least 95% for the period beginning with its in service date and ending on January 31 prior to the summer Forward Reserve Procurement Period or ending on May 31 prior to the winter Forward Reserve Procurement Period.

(b) Addition, Deactivation or Retirement of a Major Generating Resource

For the addition of a new generating Resource, the Resource must be placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the Locational Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the Locational Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

For the deactivation or retirement of a generating Resource, the Resource must have been removed from service on or before January 31 for inclusion in the analysis for setting the Locational Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before May 31 for inclusion in the analysis for setting the Locational Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

The modified historical data set will be composed of actual data used in the operation of the reconfigured system and historical (pre-reconfiguration) data adjusted for the impact of the system reconfiguration. Pre-reconfiguration data will be revised by substituting values from the historical data set that are no longer valid with corresponding values used in the operation of the reconfigured system.

The locational reserve requirements will be recalculated using the modified historical data set until the rolling two-year historical data set reflects a common system configuration.

III.9.3 Forward Reserve Auction Offers.

Forward Reserve Auction Offers for TMNSR and TMOR shall be (a) made on a $/MW-month basis, (b) made on a Reserve Zone specific basis, (c) made on a non-Resource specific basis and (d) shall be less than or equal to the Forward Reserve Offer Cap. Forward Reserve Auction Offers shall be submitted to the ISO by Market Participants. The Market Participants are responsible for complying with the requirements of this Section III.9 if the Forward Reserve Auction Offer is accepted.

III.9.4 Forward Reserve Auction Clearing and Forward Reserve Clearing Prices.

The Forward Reserve Auction shall simultaneously clear Forward Reserve Auction Offers to meet the Forward Reserve requirements for the system and each Reserve Zone using a mathematical programming algorithm. The objective of the mathematical programming based Forward Reserve Auction clearing is to minimize the total cost of Forward Reserve procured to meet the Forward Reserve requirements. The Forward Reserve Clearing Price for each Reserve Zone will reflect the cost to serve the next increment of reserve in that Reserve Zone based on the submitted Offers. The Forward Reserve Auction algorithm substitutes higher quality TMNSR for lower quality TMOR to meet system or Reserve Zone TMOR requirements when it is economical to do so provided that no constraints are violated.

The Forward Reserve Auction algorithm shall also utilize excess Forward Reserve in one Reserve Zone to meet the Forward Reserve requirements of another Reserve Zone or the system provided that the Forward Reserve can be delivered such that no constraints are violated. In addition, the Forward Reserve Auction shall apply price cascading such that the Forward Reserve Clearing Price for TMOR in a Reserve Zone is always less than or equal to the Forward Reserve Clearing Price for TMNSR in that Reserve Zone. If there is insufficient supply to meet the Forward Reserve requirements for a Reserve Zone, the Forward Reserve Clearing Price for that Reserve Zone will be set to the Forward Reserve Offer Cap.

III.9.4.1 Forward Reserve Clearing Price and Forward Reserve Obligation Publication and Correction. Market Participants with cleared Forward Reserve Auction Offers will receive a Forward Reserve Obligation for each Reserve Zone, as applicable, that is equal to the amount of Forward Reserve megawatts cleared for that Market Participant adjusted for internal bilateral transactions that transfer Forward Reserve Obligations.

(a) Within five business days after the close of the Forward Reserve Auctions, the ISO shall post Forward Reserve Clearing Prices and Forward Reserve Obligations, which shall be final as posted, not subject to correction or other adjustment, and used for the purposes of settlement, except as provided in subsections (c) and (d). The permissibility of correction of errors in sections of Market Rule 1 relating to settlement and billing processes shall not apply to Forward Reserve Clearing Prices and Forward Reserve Obligations deemed final pursuant to this Section III.9.4.1.

(b) Before posting the final Forward Reserve Clearing Prices and Forward Reserve Obligations, the ISO shall make a good faith effort when clearing those markets to discover and correct any errors that may occur due to database, software or similar errors of the ISO or its systems before publishing the final prices awarded.

(c) If the ISO determines based on reasonable belief that there may be one or more errors in the final Forward Reserve Clearing Prices and Forward Reserve Obligations or if no Forward Reserve Clearing Prices and Forward Reserve Obligations are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 11:59 p.m. of the third business day following the posting deadline specified in subsection (a), a notice that the Forward Reserve Clearing Prices and Forward Reserve Obligations are provisional and subject to correction or unavailable for initial publishing. The ISO shall confirm within three business days of posting a notice pursuant to this subsection whether there was an error in the Forward Reserve Clearing Prices and Forward Reserve Obligations and shall post a notice stating its findings.

(d) Within three business days after posting an initial notice pursuant to subsection (c); the ISO shall either: (1) publish final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations, or: (2) in the event that the ISO is unable to calculate and post final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations due to exigent circumstances not contemplated in this market rule, make an emergency filing with the Commission detailing the exigent circumstance which will not allow final Forward Reserve Clearing Prices and Forward Reserve Obligations to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

III.9.5.1 Assignment of Forward Reserve MWs to Forward Reserve Resources.

(a) Prior to the start of each Operating Day of the Forward Reserve Procurement Period, Market Participants must convert their Forward Reserve Obligations into Resource-specific obligations by assigning Forward Reserve MWs to specific eligible Forward Reserve Resources, in accordance with procedures set forth in the ISO New England Manuals. The assignment of Forward Reserve MWs to a Forward Reserve Resource must be performed by the Lead Market Participant for the Resource.

(b) A Market Participant with a Forward Reserve Obligation must have an Ownership Share in a Forward Reserve Resource, in order to assign Forward Reserve MWs to that Forward Reserve Resource to fulfill that Market Participant's Forward Reserve Obligation. If more than one Market Participant has an Ownership Share in a Forward Reserve Resource, the Forward Reserve MWs assigned to that Resource will be allocated pro-rata to Market Participants by Ownership Share.

III.9.5.2 Forward Reserve Resource Eligibility Requirements.

(a) Forward Reserve Resources are off-line or on-line Resources that have been assigned by Market Participants to meet their Forward Reserve Obligations. To be eligible as a Forward Reserve Resource, a Resource must satisfy the following criteria:

(i) If the Resource is off-line, it must be a Fast Start Generator and have an audited CLAIM10 or CLAIM30 value established pursuant to Section III.9.5.2;

(ii) If the Resource is expected to be on-line during a Forward Reserve Delivery Period, it must be able to produce the energy equivalent to its assigned Forward Reserve Obligation within the timeframe of the assigned Forward Reserve Obligation when operating within its dispatch range;

(iii) If the Resource is an Asset Related Demand, it must have an audited CLAIM10 or CLAIM30 value established pursuant to Section III.9.5.2;

(iv) The Resource must be fully listed as an Installed Capacity Resource during the delivery hour for which it has been assigned;

(v) The Resource must be able to follow ISO Dispatch Instructions;

(vi) The Resource must have Electronic Dispatch Capability; and

(vii) The Resource must meet the technical requirements associated with the provision of Forward Reserve as specified in ISO New England Operating Procedure No. 14, Technical Requirements For Generation, Dispatchable and Interruptible Loads.

(b) If a Resource's audited CLAIM10 or CLAIM30 values have not been audited or tested pursuant to Section III.9.5.2 or Section III.9.5.3 at least once during any Locational Forward Reserve Market Procurement Period, then the Resource's audited CLAIM10 or CLAIM30 values will be set to zero at the beginning of the succeeding Locational Forward Reserve Market Procurement Period until new audited CLAIM10 or CLAIM30 values are established pursuant to Section III.9.5.2. At least 30 calendar days prior to the beginning of the next Locational Forward Reserve Market Procurement Period, the ISO will notify Lead Market Participants or Designated Entities of any Resources that have not been audited or tested pursuant to Section III.9.5.2 or Section III.9.5.3 during the currently-effective Locational Forward Reserve Market Procurement Period.

(c) External Resources will be permitted to participate in the Forward Reserve Market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.9.5.3 Establishment of Audited CLAIM10 and CLAIM30 Values.

A Lead Market Participant or Designated Entity may establish an audited CLAIM10 or CLAIM30 value for a Resource by requesting either a formal audit or an economic dispatch audit. An audit request must specify the type of audit that is being requested and the target performance level that the Resource will be tested against.

In the case of a formal audit:

1. The ISO will initiate the audit by issuing Dispatch Instructions without providing prior notice to the Lead Market Participant or Designated Entity.
2. There is no compensation for any costs associated with operating a Resource out of economic merit during the audit.
3. The ISO will normally perform the audit within three business days of receipt of the audit request and will advise the Lead Market Participant or Designated Entity if it will be unable to initiate the audit during the three business day period.

In the case of an economic dispatch audit:

1. The audit is initiated when a Resource is dispatched in economic merit following receipt of the audit request.

A Resource passes an audit if its demonstrated performance level is greater than or equal to its target performance level multiplied by 0.9.

In the case of a successful audit, the Resource's audited CLAIM10 or CLAIM30 values are set equal to the target performance level to be effective as of the 0001 hours of second business day following the day on which the audit was conducted.

In the case of an unsuccessful audit:

1. If the Resource had a prior audited CLAIM10 or CLAIM30 value of zero, then the audited CLAIM10 or CLAIM30 value will be set equal to the actual performance level demonstrated during the audit effective as of the second business day following the day on which the audit was conducted.
2. If the Resource had a prior audited CLAIM10 or CLAIM30 value greater than zero, then:
   a) the audited CLAIM10 or CLAIM30 value will not be adjusted to reflect the results of the audit;
   b) In the event of a formal audit, the existing record of performance-based testing and adjustment pursuant to Section III.9.5.3 will not be modified to reflect a test failure; and
   c) In the event of an economic dispatch audit, the existing record of performance-based testing and adjustment pursuant to Section III.9.5.3 will be modified to reflect a test failure.

Except that the Lead Market Participant or Designated Entity may elect, within two business days following the day on which the audit was conducted, to direct the ISO to set the Resource's audited CLAIM10 or CLAIM30 values equal to the performance level demonstrated during the audit, which adjustment will become effective at 0001 hours on the fifth business day following the day on which the audit was conducted and in which case the record of any failures of performance-based testing pursuant to Section III.9.5.3 will be re-set to zero failures.

III.9.5.4 Performance-Based Testing and Adjustment of CLAIM10 and CLAIM30 Values.

A Resource’s audited CLAIM10 and CLAIM30 values are subject to performance-based testing and adjustment during each instance in which the Resource is issued a Dispatch Instruction (except for a Dispatch Instruction associated with a formal audit pursuant to Section III.9.5.2), including any Dispatch Instruction associated with a request for a economic dispatch audit as provided in Section III.9.5.2. In the case of a performance-based test, the demonstrated performance of the Resource is compared to the target performance level, which is the lesser of the Resource’s audited CLAIM10 or CLAIM30 value or the desired output level specified by the Dispatch Instruction.

A Resource passes a performance-based test if its demonstrated performance level is greater than or equal to its target performance level multiplied by 0.9.

If a Resource fails to pass a performance-based test, then the Resource’s audited CLAIM10 or CLAIM30 values will be adjusted as follows (with the Resource’s audited CLAIM10 or CLAIM30 value as determined pursuant to Section III.9.5.2 continuing to be used for reference purposes):

First failure – CLAIM10 or CLAIM30 value is not adjusted.

Second failure – adjusted CLAIM10 or CLAIM30 value is set equal to 0.75 multiplied by the Resource's audited CLAIM10 or CLAIM30 value.

Third failure – adjusted CLAIM10 or CLAIM30 value is set equal to 0.50 multiplied by the Resource's audited CLAIM10 or CLAIM30 value.

Fourth failure – adjusted CLAIM10 or CLAIM30 value is set equal to 0.25 multiplied by the Resource's audited CLAIM10 or CLAIM30 value.

Fifth failure – adjusted CLAIM10 or CLAIM30 value is set equal to zero.

One or more failures followed by ten consecutive passes – adjusted CLAIM10 or CLAIM30 value is re-set equal to the last audited CLAIM10 or CLAIM30 value determined pursuant to Section III.9.5.2 and the record of performance-based test failures is set equal to zero effective as of 0001 hours of the second business day following the date on which the performance-based test was conducted.

Any adjustments resulting from a failed performance-based test, except for adjustments associated with ten consecutive passes, will become effective as of 0001 hours of the fifth business day following the day on which the test was conducted.

If an audited CLAIM10 or CLAIM30 value has been adjusted as the result of a performance-based test failure, a Lead Market Participant or Designated Entity may seek to re-establish a new, audited CLAIM10 or CLAIM30 value in accordance with Section III.9.5.2.

III.9.6 Delivery of Reserve.

III.9.6.1 Dispatch and Energy Bidding of Reserve. Forward Reserve shall be delivered by Forward Reserve Resources by offering the capability into the Real-Time Energy Market by submitting Supply Offers and Demand Bids at or above the Forward Reserve Threshold Price (as calculated pursuant to Section III.9.6.2 of this Market Rule).

The Forward Reserve Threshold Prices shall be set in accordance with the ISO New England Manuals so that Forward Reserve Resource capability has (a) a low probability of being dispatched for energy and (b) a high probability of being held for reserve purposes.

Forward Reserve Resources are scheduled and operated in accordance with Section III.1 of this Market Rule; no distinction is made due to their status as Forward Reserve Resources. Forward

Reserve Resources are eligible to set the Locational Marginal Price in accordance with Section III.2 of this Market Rule.

III.9.6.2 **Forward Reserve Threshold Prices**. The formula for determining the monthly Forward Reserve Threshold Prices shall be fixed for the duration of the Forward Reserve Procurement Period. The ISO will reevaluate the Forward Reserve Threshold Price level for successive Forward Reserve Auctions on the basis of experience, expected operating conditions and other relevant information.

Forward Reserve Threshold Price: is calculated as the Forward Reserve Heat Rate multiplied by the monthly Forward Reserve Fuel Index.

Forward Reserve Heat Rate: shall be fixed for the duration of the Forward Reserve Procurement Period and announced in the announcement for the Forward Reserve Auction. New Forward Reserve Heat Rates shall be specified for successive auctions.

Forward Reserve Fuel Index: is the monthly fuel index, or combination of monthly indices, applicable to the New England Control Area and specified in the announcement of the Forward Reserve Auction. The monthly Forward Reserve Fuel Index for a Forward Reserve Procurement Period shall be specified prior to the start of each month of the Forward Reserve Procurement Period.

III.9.6.3 **Monitoring of Forward Reserve Resources.** In accordance with Section III.A.9.4 of ***Appendix A*** of this Market Rule 1, the Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Participant in accordance with Market Rule 1, ***Appendix A***, Section III.A.3. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4.

III.9.6.4 **Forward Reserve Qualifying Megawatts.** Qualifying megawatts are calculated separately on an hourly basis for Forward Reserve Resources supplying Forward Reserve from an off-line state and Forward Reserve Resources supplying Forward Reserve from an on-line state as follows:

<u>Off-line qualifying megawatts</u>. Off-line qualifying megawatts are the amount of capability equal to or below the Economic Maximum Limit for an off-line Forward Reserve Resource offered at or above the Forward Reserve Threshold Price. The generating Resource must satisfy this requirement in the Real-Time Energy Market. In the case of off-line Forward Reserve Resource, the calculation for Forward Reserve Qualifying Megawatts shall include both the energy Supply Offer and a pro-rated amount of Start-Up Fees and No-Load Fees as defined below.

An off-line Forward Reserve Resource must offer its capability so that the following holds:

$$\frac{StartUp}{EcoMax \times 1 \text{ hour}} + \frac{NoLoad}{EcoMax} + Energy\ Offer_i \geq ForwardReserveThresholdPrice$$

where:

StartUp = the generating Resource's cold Start-Up Fee.

NoLoad = the generating Resource's No-Load Fee.

$EnergyOffer_i$ = the generating Resource's Energy Offer for Energy Offer block i.

EcoMax = the Economic Maximum Limit.

On-line qualifying megawatts: is the capability that is less than or equal to the Economic Maximum Limit and above the Economic Minimum Limit that is offered at or above the applicable Forward Reserve Threshold Price by an on-line generating Resource or, is the capability that is less than or equal to the Maximum Consumption Limit and greater than the Minimum Consumption Limit offered at or above the applicable Forward Reserve Threshold Price by a Dispatchable Asset Related Demand Resource. The Forward Reserve Resource must satisfy this requirement in the Real-Time Energy Market. For an on-line generating Resource that has been assigned to meet a Forward Reserve Obligation and has not cleared in the Day-Ahead Energy Market and is operating in a delivery hour as the result of an ISO commitment for VAR or Local Second Contingency Protection, the on-line qualifying megawatts shall be zero.

III.9.6.5 **Delivery Accounting.** Forward Reserve Delivered megawatts is the quantity of Forward Reserve delivered in each hour of the Real-Time Energy Market to each Reserve Zone and is calculated as follows.

(a) Forward Reserve Delivered Megawatts for an off-line Forward Reserve Resource are calculated in megawatts for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount, in MW, of Forward Reserve that the off-line generating Resource can provide, based upon CLAIM10 and CLAIM30 values provided in the generating Resource's Real-Time Supply Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (energy at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(b) Forward Reserve Delivered Megawatts for an on-line generating Resource are calculated in megawatts for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramping rate of the on-line generating Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(c) Forward Reserve Delivered Megawatts for a Dispatchable Asset Related Demand are calculated in megawatts for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramp rate of the Resource, as applicable,

(ii) the amount of Forward Reserve capability specified in the Resource's CLAIM10 and CLAIM30 values,

(iii) Forward Reserve Assigned Megawatts, or

(iv) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2),

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(d) <u>A Forward Reserve Resource's hourly Forward Reserve Delivered Megawatts for each Reserve Zone</u> is calculated as the sum of the Market Participant's Resource specific hourly Forward Reserve Delivered Megawatts for each Reserve Zone.

(e) Resource specific Forward Reserve Delivered Megawatts for TMNSR within a Reserve Zone will be applied first to a Market Participant's higher value Forward Reserve Obligation for TMNSR in that Reserve Zone. Any surplus Forward Reserve Delivered Megawatts for TMNSR in that Reserve Zone will be applied to meet the Market Participant's Forward Reserve Obligation for TMOR in that Reserve Zone. Forward Reserve Delivered Megawatts remaining within that Reserve Zone after the Market Participant's Forward Reserve Obligation for that Reserve Zone have been met is available to be applied to the Market Participant's Forward Reserve Obligations in other Reserve Zones provided that the Forward Reserve Delivered Megawatts can be delivered to the other Reserve Zones.

III.9.7 Consequences of Delivery Failure.

III.9.7.1 Real-Time Failure-to-Reserve. A Real-Time Failure-to-Reserve occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

(a) Forward Reserve Failure-to-Reserve Megawatts: A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMNSR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(i) (Market Participant Forward Reserve Obligation for TMNSR for that Reserve Zone minus

(Market Participant's Forward Reserve Delivered Megawatts for TMNSR for that Reserve Zone plus that Market Participant's Approved Outage Forward Reserve Assigned Megawatts for TMNSR for that Reserve Zone); and

(ii) Zero.

Where:

Approved Outage Forward Reserve Assigned Megawatts for TMNSR are calculated only for Resources in the Reserve Zones defined in Section III.2.7(c) of this Market Rule 1, and are equal to the sum of, for any such Reserve Zone, the TMNSR megawatts assigned to Resources that are on the ISO-approved annual maintenance schedule as of September 30 for the Winter Capability Period or as of May 31 for the Summer Capability Period, or that are on a scheduled maintenance outage that has been moved at the ISO's request, and where such assigned megawatts, by Resource, are limited to the Resource's Seasonal Claimed Capability for a Fast Start Generator or limited to the Resource's ramp rate multiplied by 10 if the Resource is not a Fast Start Generator.

A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMOR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(i) Market Participant Forward Reserve Obligation for TMOR for that Reserve Zone minus (Market Participant's Forward Reserve Delivered Megawatts for TMOR for that Reserve Zone plus that Market Participant's Approved Outage Forward Reserve Assigned Megawatts for TMOR for that Reserve Zone); and

(ii) Zero.

Where:

Approved Outage Forward Reserve Assigned Megawatts for TMOR are calculated only for Resources in the Reserve Zones defined in Section III.2.7(c) of this Market Rule 1, and are equal to the sum of, for any such Reserve Zone, the TMOR megawatts assigned to Resources that are on the ISO-approved annual maintenance schedule as of September 30 for the Winter Capability Period or as of May 31 for the Summer Capability Period, or that are on a scheduled maintenance outage that has been moved at the ISO's request, and where such assigned megawatts, by Resource, are limited to the Resource's Seasonal Claimed Capability for a Fast Start Generator or limited to the Resource's ramp rate multiplied by 30 if the Resource is not a Fast Start Generator.

(b) Forward Reserve Failure-to-Reserve Penalties: A Market Participant's Forward Reserve Failure-to-Reserve Penalty for a Reserve Zone in an hour is defined as:

(i) Forward Reserve Failure-to-Reserve Penalty for TMNSR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Reserve Penalty for TMOR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Reserve Penalty Rate = 1.5 multiplied by the Forward Reserve Payment Rate

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III.9.7.2 **Failure-to-Activate Penalties.** Market Participants are required to pay a Failure-to-Activate Penalty for each Forward Reserve Resource that fails to activate its Forward Reserve capability when requested to do so by the ISO as part of the real-time contingency dispatch algorithm.

When a Market Participant's Forward Reserve Resource has been determined by the ISO to have failed to activate Forward Reserve, which determination shall be made in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, that Market Participant shall be required to pay a Failure-to-Activate Penalty associated with that Resource as follows:

(a) **Forward Reserve Failure-to-Activate Megawatts**: A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMNSR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(i) Maximum of Forward Reserve Delivered Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

(ii) Maximum of Target Activation Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMNSR is the target MW output issued by the ISO in a Dispatch Instruction for that Resource in response to a need to activate TMNSR.

A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMOR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(i) Maximum of Forward Reserve Delivered Megawatts for TMOR plus Forward Reserve Delivered Megawatts for TMNSR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

(ii) Maximum of Target Activation Megawatts for TMOR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMOR is the target MW output issued by the ISO in a Dispatch Instruction for that Resource in response to a need to activate TMOR.

(b) **Forward Reserve Failure-to-Activate Penalties**: A Market Participant's Forward Reserve Failure-to-Activate Penalty for a Resource in an hour is defined as:

(i) Forward Reserve Failure-to-Activate Penalty for TMNSR = The sum of the Forward Reserve Payment Rate for TMNSR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Activate Penalty for TMOR = The sum of the Forward Reserve Payment Rate for TMOR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Activate Penalty Rate = Maximum of 2.25 multiplied by the Forward Reserve Payment Rate, or the applicable Nodal LMP.

(c) A Forward Reserve Resource that is a Fast Start Generator that fails to activate Forward Reserve through a Failure to Start shall have its Forward Reserve Delivered Megawatts set equal to zero in each subsequent hour in the applicable Forward Reserve Service Period until such time that the Market Participant notifies the ISO that the subject Forward Reserve Resource is capable of providing the Forward Reserve Delivered Megawatts.

III.9.7.3 Known Performance Limitations. The ISO may have reason to believe that a particular Forward Reserve Resource is frequently receiving, or may frequently receive, Forward Reserve payments for a portion or all of its capability that is not capable of activating the Forward TMNSR Assigned Megawatts or the Forward TMOR Assigned Megawatts. When the ISO believes there is such a limited Forward Reserve Resource, the ISO shall contact and confer with the affected Market Participant before taking any action.

(a) The ISO will, whenever practicable, contact the affected Market Participant of the Forward Reserve Resource to request an explanation of the relevant resource Offer Data;

(b) If the explanation, if available, considered together with other information available to the ISO, indicates to the satisfaction of the ISO that the questioned Forward Reserve payments are consistent with Forward Reserve Resource capabilities, no further action will be taken; and

(c) If no agreement is reached, or an acceptable explanation is not provided, the Market Participant may request a Resource performance audit as specified in ISO New England Manuals. If the Forward Reserve Resource fails the performance audit or the Market Participant refuses to request a Resource performance audit, the ISO may take remedial action. Remedial actions may include, but are not limited to: (i) redeclaration, by the ISO, of any relevant operational Offer Data parameter, or (ii) removing the asset or the relevant portion of the asset's capability to provide Forward Reserve on a going-forward basis.

III.9.8 Forward Reserve Credits. Payment for Forward Reserve is based upon a Market Participant's Final Forward Reserve Obligation and the applicable Forward Reserve Clearing Prices. The ISO shall calculate these credits on an hourly basis for each Reserve Zone as follows:

(a) Final Forward Reserve Obligations for TMNSR and TMOR for each Market Participant are calculated for each Reserve Zone for each hour as follows:

(i) Final Forward Reserve Obligation = minimum [Forward Reserve Obligation, Forward Reserve Delivered Megawatts]

(b) Market Participant Forward Reserve Credit for TMNSR = Final Forward Reserve Obligation for TMNSR x applicable hourly Forward Reserve Payment Rate for TMNSR;

where,

the hourly Forward Reserve Payment Rate for TMNSR is equal to maximum of [(applicable monthly Forward Reserve Clearing Price for TMNSR – that month's ICAP Transition Rate), 0] divided by the hours in the month associated with the on-peak period.

(c) Market Participant Forward Reserve Credit for TMOR = Final Forward Reserve Obligation for TMOR x applicable hourly Forward Reserve Payment Rate for TMOR;

where,

the hourly Forward Reserve Payment Rate for TMOR is equal to maximum of [(applicable monthly Forward Reserve Clearing Price for TMOR – that month's ICAP Transition Rate), 0] divided by the hours in the month associated with the on-peak period.

III.9.9 Forward Reserve Charges. For each hour, the ISO will allocate the total of the Forward Reserve Credits, Forward Reserve Failure-to-Reserve Penalties, Forward Reserve Failure-to-Activate Penalties for each Load Zone that are calculated separately for TMNSR and TMOR, to each Market Participant for each hour, as follows:

Forward Reserve $\text{Charge}_{k,i}$ = [Reserve Charge Allocation $\text{MWs}_{\text{k,i}}$] x [FR_CHRG_RT_i]

Where:

Forward Reserve $\text{Charge}_{k,i,}$ is Market Participant *k's* Forward Reserve Charge for Load Zone *i* for TMNSR or TMOR, as applicable;

Reserve Charge Allocation MWs = Market Participant *k*'s Real Time Load Obligation in Load Zone *i* adjusted for Market Participant *k*'s Dispatchable Asset Related Demand MWs in Load Zone *i* that are designated for real-time reserves,

FR_CHRG_RT_i = [[FR_SUP_PMNT] / [FR_P_WTD_LD_OB]] x [P_RATIO_i] for TMNSR or TMOR, as applicable;

FR_P_WTD_LD_OB = $\sum_i$ [Reserve Charge Allocation MWs_i] x [P_RATIO_i] for TMNSR or TMOR, as applicable;

[FR_SUP_PMNT] = The total over all Load Zones of Forward Reserve Credits for TMNSR or TMOR plus the total over all Load Zones of Forward Reserve Failure-to Reserve Penalties for TMNSR or TMOR plus the total over all Load Zones of Forward Reserve Failure-to-Activate Penalties for TMNSR or TMOR, plus the total over all Load Zones of Forward Reserve Failure-to-Activate Penalties for TMNSR or TMOR, as applicable;

$FR\_P\_RATIO_i$ is the ratio of the Forward Reserve Clearing Prices in Load Zone *i* for TMNSR, or TMOR, as applicable, to the Forward Reserve Clearing Prices in the Reference Load Zone for TMNSR, or TMOR, as applicable. To the extent that a Load Zone contains more than one Reserve Zone, that Load Zone's Forward Reserve Clearing Price shall be the Forward Reserve Auction Reserve Zone cleared MW weighted average of the Reserve Zone Forward Reserve Clearing Prices in that Load Zone;

The Reference Load Zone is the Load Zone with the minimum, non-zero Forward Reserve Clearing Price for TMNSR or TMOR, as applicable.

III.10 Real-Time Reserve

The ISO shall use a joint optimization dispatch algorithm to serve Real-Time Energy Market requirements and meet Real-Time Operating Reserve requirements based on a least-cost security constrained economic dispatch. The Real-Time dispatch algorithm will designate Resources to meet the Energy requirements and will designate Resources to meet the Operating Reserve requirements of the New England Control Area.

III.10.1 Provision of Operating Reserve in Real-Time

For each Market Participant for each hour, the ISO will determine each Market Participant's provision of Operating Reserve in Real-Time. To accomplish this, the ISO will perform calculations to determine the following.

III.10.1.1 Real-Time Reserve Designation

Each Market Participant shall have for each hour and for each eligible generating Resource capable of providing Operating Reserve a Real-Time Reserve Designation, in megawatts, equal to the amounts of Operating Reserve designated by the ISO to that Resource in Real-Time adjusted downward after-the-fact, if necessary, to account for differences in actual Resource output based upon revenue quality meter readings and the estimated Resource output utilized to determine the amount of Real-Time Reserve Designation. Each Market Participant shall have for each hour and for each eligible Asset Related Demand Resource capable of providing Operating Reserve a Real-Time Reserve Designation, in megawatts, equal to the amounts of Operating Reserve designated by the ISO to that Resource in Real-Time adjusted downward after-the-fact, if necessary, to account for differences in actual Resource consumption based upon revenue quality meter readings and the estimated Resource consumption utilized to determine the amount of Real-Time Reserve Designation. Resource eligibility to provide Operating Reserve shall be specified in the ISO New England Manuals.

III.10.2 Real-Time Reserve Credits

For each Market Participant for each hour, the ISO will determine a credit for provision of Operating Reserve in Real-Time.

(a) A Market Participant's Resource specific Real-Time Reserve Credit for TMSR shall be equal to that Market Participant's Resource specific Real-Time Reserve Designation for TMSR multiplied by the Real-Time Reserve Clearing Price for TMSR. The Real-Time Reserve Credit for TMSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMSR in that Load Zone.

(b) A Market Participant's Resource specific Real-Time Reserve Credit for TMNSR shall be equal to that Market Participant's Resource specific Real-Time Reserve Designation for

TMNSR multiplied by the Real-Time Reserve Clearing Price for TMNSR. The Real-Time Reserve Credit for TMNSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMNSR in that Load Zone.

(c) A Market Participant's Resource specific Real-Time Reserve Credit for TMOR shall be equal to that Market Participant's Resource specific Real-Time Reserve Designation for TMOR multiplied by the Real-Time Reserve Clearing Price for TMOR. The Real-Time Reserve Credit for TMOR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMOR in that Load Zone.

III.10.3 Real-Time Reserve Charges.

(a) For each hour, the ISO will as allocate the sum of the Real-Time Reserve Credits and Forward Reserve Obligation Charges for each Load Zone, calculated separately for TMSR, TMNSR and TMOR, to each Market Participant as follows:

Real-Time Reserve Charge$_{k,i}$ = [Reserve Charge Allocation MW$_{k,I}$] x [RT_CHRG_RT$_i$]

Where:

Real-Time Reserve Charge$_{k,i,}$ is Market Participant *k's* Real-Time Reserve Charge for Load Zone *i* for all Real-Time reserve services and Forward Reserve Obligation Charges;

Reserve Charge Allocation MW = Market Participant *k*'s Real Time Load Obligation in Load Zone *i* adjusted for Market Participant *k*'s Dispatchable Asset Related Demand MWs in Load Zone *i* that are designated for Real-Time reserves.

$RT\_CHRG\_RT_i$ = [IRT_SUP_PMNT]/RT_P_WTD_LD_OB] x [RT_P_RATIO] for TMSR, TMNSR, or TMOR, as applicable.

RT_P_WTD_LD_OB = ∑[Reserve Charge Allocation MWsi] x [P_RATIOi] for TMSR, TMNSR or TMOR, as applicable;

[RT_SUP_PMNT] = The total over all Load Zones of Real-Time Reserve Credits for TMSR, TMNSR or TMOR, plus the total over all Load Zones of the Forward Reserve Obligation Charges for TMNSR or TMOR, as applicable;

RT_P_RATIOi is the ratio of the Real Time Reserve Clearing Price in Load Zone i for TMSR, TMNSR or TMOR, as applicable, to the Real -Time Reserve Clearing Price in the Reference Zone for TMSR, TMNSR or TMOR, as applicable. To the extent that a Load Zone contains more than one Reserve Zone, that Load Zone's Real-Time Reserve Clearing Price for TMSR, TMNSR or TMOR shall be the Real-Time Reserve Designation weighted average of the Reserve Zone Real-Time Reserve Clearing Prices in that Load Zone for TMSR, TMNSR or TMOR, as applicable;

The Reference Load Zone is the Load Zone with the minimum, non-zero Real-Time Reserve Clearing Price for TMSR, TMNSR or TMOR, as applicable.

III.10.4 Forward Reserve Obligation Charges

For each Market Participant with a Forward Reserve Obligation, the ISO will determine a Forward Reserve Obligation Charge for each hour such that a Market Participant will not receive compensation for the provision of both Real-Time Operating Reserve MWs and Forward Reserve MWs for the same reserve service.

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III.10.4.1 Forward Reserve Obligation Charge Megawatts for Forward Reserve Resources.

The Forward Reserve Obligation Charge Megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Forward Reserve Resource are equal to the lesser of the Forward Reserve Delivered MW or Real-Time Reserve Designation MW.

III.10.4.2 Forward Reserve Obligation Charge Megawatts.

The Forward Reserve Obligation Charge Megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Market Participant is equal to the lesser of the sum of Forward Reserve Obligation Charge Megawatts for all the Reserve Resources assigned by the Market Participant, or the Final Forward Reserve Obligation

III.10.4.3 Forward Reserve Obligation Charge. The Forward Reserve Obligation Charge will be calculated as follows:

(a) A Market Participant's Forward Reserve Obligation Charge for TMNSR in each Reserve Zone shall be equal to the Market Participant's Forward Reserve Obligation Charge Megawatts for TMNSR in that Reserve Zone multiplied by the Real-Time Reserve Clearing Price for TMNSR in that Reserve Zone.

(b) A Market Participant's Forward Reserve Obligation Charge for TMOR in each Reserve Zone shall be equal to the Market Participant's Forward Reserve Obligation Charge Megawatts for TMOR in that Reserve Zone multiplied by the Real-Time Reserve Clearing Price for TMOR in that Reserve Zone.

III.11 Gap RFPs For Reliability Purposes

III.11.1 Request For Proposals for Load Response and Supplemental Generation Resources for Reliability Purposes.

(a) Should the ISO determine that a region may have potential critical near-term power supply reliability problems for which no Market Participant has proposed or committed to implement a viable solution (from a timeliness or financial standpoint), the ISO may, after consultation with the Reliability Committee, issue a request for proposals (Gap RFP). The Gap RFP will solicit load response and supplemental generating Resources to maintain near-term reliability in the identified region. For any Gap RFP issued after December 31, 2003, the ISO shall file such Gap RFP with the Commission for approval at least 60 days prior to its issuance. The filing shall include proposed Gap RFP terms and conditions and shall explain why market incentives were unable to solicit a market response in the absence of the Gap RFP.

(b) The ISO may enter into contracts awarded pursuant to a competitive Gap RFP process. Bidders that are awarded contracts through the Gap RFP process shall file those contracts with the Commission for approval of the rates to be charged thereunder to the extent that such contracts are for services that are jurisdictional to the Commission. All other contracts entered into pursuant to a Gap RFP shall be filed with the Commission for informational purposes.

(c) The costs for load response and other generation Resources selected through any Gap RFP issued by the ISO pursuant to this Section III.11.1 shall be allocated and charged in the same manner as fixed-cost charges associated with Local Second Contingency Protection Resources under Section III.6.4.4(c) of this Market Rule.

III.12 Calculation of Capacity Requirements

III.12.1 Installed Capacity Requirement. Prior to each Forward Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for each upcoming Capability Year through the Capacity Commitment Period associated with that Forward Capacity Auction in accordance with this Section III.12.1. The ISO shall calculate the Installed Capacity Requirement for the New England Control Area for any Capability Year during the ICAP Transition Period in accordance with this Section III.12.1 to the extent applicable and practicable.

The ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on the average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion each Capability Year. The Installed Capacity Requirement shall be determined assuming all resources pursuant to Sections III.12.7 and III.12.9 will be deliverable to meet the forecasted demand determined pursuant to Section III.12.8.

If the Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Installed Capacity Requirement.

The modeling assumptions used in determining the Installed Capacity Requirement are specified in Sections III.12.7, III.12.8 and III.12.9. For the purpose of this Section III.12, a "resource" shall include generating resources, demand resources, and import capacity resources eligible to receive capacity payments in the Forward Capacity Market.

III.12.2 Local Sourcing Requirements and Maximum Capacity Limits. Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section III.12.5, for each Load Zone for each upcoming Capability Year through the Capacity Commitment Period associated with that Forward Capacity Auction. The Local Sourcing Requirement shall represent the minimum amount of capacity that must be electrically located within an import-constrained Load Zone. The Maximum Capacity Limit shall represent the maximum amount of capacity that can be procured in an export-constrained Load Zone to meet the Installed Capacity Requirement.

The ISO shall use consistent assumptions and standards to establish a resource's electrical location for purposes of qualifying a resource for the Forward Capacity Market and for purposes of calculating Local Sourcing Requirements.

Load Zones will be reconfigured as necessary pursuant to Section III.2.7(g) of Market Rules.

The methodology used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.2.1 and III.12.2.2, respectively. The modeling assumptions used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.5, III.12.7, III.12.8 and III.12.9.

III.12.2.1 Calculation of Local Sourcing Requirements for Import-Constrained Load Zones. For each import-constrained Load Zone, the Local Sourcing Requirement shall be calculated using the following method:

(a) Two areas shall be modeled: (i) the Load Zone under study which includes all load and all resources electrically located within the Load Zone, including external Control Area support from tie benefits on the import-constrained side of the interface, if any; and (ii) the rest of the New England Control Area which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits on the unconstrained side of the interface, if any.

(b) The only transmission constraint to be modeled shall be the transmission interface limit between the Load Zone under study and the rest of the New England Control Area as determined pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE with proxy units added is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Local Sourcing Requirement for the import-constrained Load Zone Z shall be determined in accordance with the following formula:

$LSR_Z = Resources_Z + Proxy\ Units_Z – (Proxy\ Units\ Adjustment_Z/(1 – FOR_Z)) – (Firm\ Load\ Adjustment_Z/(1 – FOR_Z))$

In which:

LSR_Z	=	MW of Local Sourcing Requirement for Load Zone Z;
$Resources_Z$	=	MW of resources electrically located within Load Zone Z, including Import Capacity Resources on the import-constrained side of the interface, if any;
$Proxy\ Units_Z$	=	MW of proxy unit additions in Load Zone Z;
$Firm\ Load\ Adjustment_Z$	=	MW of firm load added (or subtracted) within Load Zone Z to make the LOLE of the New England Control Area equal to 0.105 days per year; and
FOR_Z	=	Capacity weighted average of the forced outage rate modeled for all resources within Load Zone Z, including any proxy unit additions to Load Zone Z.

Proxy Units Adjustment	=	MW of firm load added to (or unforced capacity subtracted from) Load Zone Z until the system LOLE equals 0.1 days/year.

To determine the Local Sourcing Requirement, the firm load is adjusted within Load Zone Z until the LOLE of the New England Control Area reaches 0.105 days per year. The LOLE of 0.105 days per year includes an allowance for transmission related LOLE of 0.005 days per year associated with each interface. As firm load is added to (or subtracted from) Load Zone Z, an equal amount of firm load is removed from (or added to) the rest of New England Control Area.

III.12.2.2 Calculation of Maximum Capacity Limit for Export-Constrained Load Zones. For each export-constrained Load Zone, the Maximum Capacity Limit shall be calculated using the following method:

(a) Two areas shall be modeled: (i) the Load Zone under study which includes all load and all resources electrically located within the Load Zone, including external Control Area support from tie benefits on the export-constrained side of the interface, if any; and (ii) the rest of the New England Control Area, which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits to the rest of New England Control Area, if any.

(b) The only transmission constraint to be modeled shall be the transmission interface limit between the Load Zone under study and the rest of the New England Control Area as determined pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE with proxy units added is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Maximum Capacity Limit for the export-constrained Load Zone Y shall be determined in accordance with the following formula:

$$\text{Maximum Capacity Limit}_Y = ICR - LSR_{RestofNewEngland}$$

In which:

Maximum Capacity Limit$_Y$	=	Maximum MW amount of resources , including Import Capacity Resources on the export-constrained side of the interface, if any, that can be procured in the export-constrained Load Zone Y to meet the Installed Capacity Requirement;
ICR	=	MW of Installed Capacity Requirement for the New England Control Area, determined in accordance with Section III.12.1; and
$LSR_{RestofNewEngland}$	=	MW of Local Sourcing Requirement for the rest of the New England Control Area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Section III.12.2.1.

III.12.3 Consultation and Filing of Capacity Requirements. At least two months prior to filing the Installed Capacity Requirements and Local Souring Requirements for each upcoming Capability Year through the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirements and the Local Sourcing Requirements with the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies.

Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirements and Local Sourcing Requirements for each upcoming Capability Year through the relevant Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act 90 days prior to the Forward Capacity Auction for the Capacity Commitment Period.

III.12.4 Determination of Capacity Zones. Prior to each Forward Capacity Auction, the ISO shall determine the Capacity Zones to be modeled in that Forward Capacity Auction as specified below:

(a) Each export-constrained Load Zone shall be modeled as a separate Capacity Zone in the Forward Capacity Auction.

(b) For each import-constrained Load Zone, the ISO shall determine the total amount of capacity that is projected to be installed in that Load Zone before the start of the relevant Capacity Commitment Period, by summing the summer Qualified Capacity of Existing Generating Capacity Resources, resources cleared in previous Forward Capacity Auctions, Existing Demand Resources qualified to participate in the Forward Capacity Market and Other Demand Resources in existence during the ICAP Transition Period and Import Capacity Resources cleared in previous Forward Capacity Auctions or reconfiguration auctions and obligated for the relevant Capacity Commitment Period. The total amount of capacity that is projected to be installed before the start of the relevant Capacity Commitment Period shall exclude capacity that for the relevant Capacity Commitment Period is subject to either a Permanent De-List Bid cleared in previous Forward Capacity Auctions or Administrative Export De-List Bid obligated for the relevant Capacity Commitment Period. The ISO shall compare the total amount of capacity that is projected to be installed in the import-constrained Load Zone before the start of the relevant Capacity Commitment Period to that Load Zone's forecasted Local Sourcing Requirement for the relevant Capacity Commitment Period as determined pursuant to Section III.12.2.1. If the total amount of capacity that is projected to be installed in the import-constrained Load Zone before the start of the relevant Capacity Commitment Period is greater than the sum of that Load Zone's forecasted Local Sourcing Requirement and any (i) Export Bids or (ii) Administrative Export De-List Bids, which may be exporting capacity through the import-constrained Load Zone, limited to the transfer limit of the relevant external interface, for the relevant Capacity Commitment Period as determined pursuant to Section III.12.2.1, the Load Zone shall not be modeled as a separate Capacity Zone in the Forward Capacity Auction. Otherwise, the import-constrained Load Zone shall be modeled as a separate Capacity Zone in the Forward Capacity Auction.

(c) Adjacent Load Zones that are neither export-constrained nor import-constrained shall together be modeled as a single Capacity Zone.

III.12.5 Transmission Interface Limits. Transmission interface limits, used in the determination of Local Sourcing Requirements, shall be determined using network models that include all resources , existing transmission lines and proposed transmission lines that the ISO determines, in accordance with Section III.12.6, will be in service no later than the first day of the relevant Capacity Commitment Period. Load modeling assumptions used in determining the transmission interface limits are specified in Section III.12.8. The transmission interface limits shall be calculated assuming simultaneous imports from directly connected Control Areas up to the level of tie benefits that may be assumed over the applicable interface.

Prior to each Forward Capacity Auction, the ISO shall update the transmission interface limits for each internal and external interface for each upcoming Capability Year through the Capacity Commitment Period associated with that Forward Capacity Auction. This update shall take into account any additional transmission projects and elements of transmission projects that are added to the network model pursuant to Section III.12.6. The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

III.12.6 Modeling Assumptions for Determining the Network Model. The ISO shall determine, in accordance with this Section III.12.6, the generating units and transmission infrastructure to include in the network model that: (i) are expected to be in service no later than the first day of the relevant Capacity Commitment Period; and (ii) may have a material impact on the network model, a potential interface constraint, or on one or more Local Sourcing Requirements. The network model shall be used, among other purposes, (i) for the Forward Capacity Market qualification process and (ii) to calculate transmission interface limits in order to forecast the Local Sourcing Requirements. The network model shall include generating units and associated Interconnection Facilities as specified in subsection (a) and Transmission Upgrades as specified in subsection (b).

(a) Generating units and associated Interconnection Facilities that shall be included in the network model for the relevant Capacity Commitment Period shall include:

i. all existing generating units that have not been approved to be retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff or deemed to be retired pursuant to Section II.47 of the Transmission, Markets and Services Tariff;

ii. all generating units that are resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that have a valid Interconnection Request for which a draft Interconnection System Impact Study report has been submitted to the Interconnection Customer; and

iii. any generating unit that has a valid Interconnection Request for which a draft Interconnection Feasibility Study report has been submitted to the Interconnection Customer and is reasonably expected to declare commercial operation no later than the first day of the relevant Capacity Commitment Period whether or not such unit is participating in the Forward Capacity Market qualification process.

(b) Prior to each Forward Capacity Auction and each annual reconfiguration auction, the ISO shall determine and publish a list of the transmission projects and elements of transmission projects that will be included in the network model. During the process of making the transmission infrastructure determinations, as described in Section III.12.6.1, the ISO shall consult with the Governance Participants, the Transmission Owners, any transmission project proponents, the state utility regulatory agencies in New England and, as appropriate, other state agencies.

III.12.6.1 Process for Establishing the Network Model

(a) The ISO shall establish an initial network model prior to the Forward Capacity Auction that only includes transmission infrastructure that is already in service at the time that the initial network model is developed.

(b) After establishing the initial network model, the ISO shall compile a preliminary list of the transmission projects or elements of transmission projects in the Transmission Project Listing, individually or in combination with each other, as appropriate, to identify transmission projects that may achieve an in-service date no later than the first day of the relevant Capacity Commitment Period and that will have a material impact on the network model, on a potential interface constraint or one or more Local Sourcing Requirements.

(c) For the transmission projects or elements of transmission projects in the Transmission Project Listing that are included in the preliminary list developed pursuant to subsection (b), the ISO shall determine whether the transmission projects or elements of transmission projects meet all of the initial threshold milestones specified in Section III.12.6.2 and will be considered for further evaluation pursuant to subsection (d).

(d) For those transmission projects or elements of transmission projects that meet the initial threshold milestones in subsection (c), the ISO shall use the evaluation criteria specified in Section III.12.6.3, and any other relevant information, to determine whether to include a transmission project or element of a transmission project in the final network model.

(e) If after completing its evaluation pursuant to Sections III.12.6.1 through III.12.6.3 and conferring with the transmission project proponents, the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO determines that the transmission project or a portion of the transmission project is reasonably expected to be in service no later than the first day for the relevant Capacity Commitment Period, then such transmission project or portion of transmission project shall be considered in service in the finalized network model to calculate the transmission interface limits pursuant to Section III.12.5.

III.12.6.2 Initial Threshold to be Considered In-Service. The ISO shall determine whether transmission projects or elements of transmission projects meet all of the following initial threshold milestones:

(a) A critical path schedule for the transmission project has been furnished to ISO showing that the transmission project or the element of the transmission project will be in-service no later than the first day of the relevant Capacity Commitment Period. The critical path schedule must be sufficiently detailed to allow the ISO to evaluate the feasibility of the schedule.

(b) At the time of the milestone review, siting and permitting processes, if required, are on schedule as shown on the critical path schedule.

(c) At the time of the milestone review, engineering is on schedule as shown on the critical path schedule.

(d) At the time of the milestone review, land acquisition, if required, is on schedule as shown on the critical path schedule.

(e) Corporate intent to build the transmission project has been furnished to the ISO. An officer of the host Transmission Owner has submitted to the ISO a statement verifying that the officer has reviewed the proposal and critical path schedule submitted to the ISO, and the Transmission Owner concurs that the schedule is achievable, and it is the intent of the Transmission Owner to build the proposed transmission project in accordance with that schedule. The Transmission Owner may develop alternatives or modifications to the transmission project during the course of design of the transmission project that accomplish at least the same transfer capability. Such alternatives or modifications are acceptable, so long as the ISO determines that the alternative or modification is reasonably expected to achieve an in-service date no later than the first day of the relevant Capacity Commitment Period. The provision of an officer's statement shall be with the understanding that the statement shall not create any liability on the officer and that any liability with respect to the Transmission Owner's obligations shall be as set forth in the Transmission Operating Agreement and shall not be affected by such officer's statement.

III.12.6.3 Evaluation Criteria. For a transmission project or element of a transmission project that meets the initial threshold milestones specified in Section III.12.6.2, the ISO shall consider the following factors and any other relevant information to determine whether to include the transmission project or element of the transmission project in the network model for the relevant Capacity Commitment Period.

(a) Sufficient engineering to initiate construction is on schedule as shown on the critical path schedule.

(b) Approval under Section I.3.9 of the Transmission, Markets and Services Tariff, if required, has been obtained or is on schedule to be obtained as shown on the critical path schedule.

(c) Significant permits, including local permits, if required to initiate construction have been obtained or are on schedule consistent with the critical path schedule.

(d) Easements, if required, have been obtained or are on schedule consistent with the critical path schedule. Needed land purchases, if required, have been made or are on schedule consistent with the critical path schedule.

(e) Any contracts required to procure or construct a transmission project are in place consistent with the critical path schedule. The ISO's analysis may also take into account whether such contracts contain incentive and/or penalty clauses to encourage third parties to advance the delivery of material services to conform with the critical path schedule.

(f) Physical site work is on schedule consistent with the critical path schedule.

(g) The transmission project is in a designated National Interest Electric Transmission Corridor in accordance with Section 216 of the Federal Power Act, 16 U.S.C. §§ 824p.

III.12.7 Resource Modeling Assumptions.

III.12.7.1 Proxy Units. When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as additional capacity to determine the Installed Capacity Requirement and the Local Sourcing Requirements. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all other resources in the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

When modeling transmission constraints for the determination of Local Sourcing Requirements, the same proxy units may be added to the import-constrained Load Zone or elsewhere in the rest of the New England Control Area depending on where system constraints exist.

III.12.7.2 Capacity. The resources included in the calculation of the Installed Capacity Requirement and the Local Sourcing Requirements shall include:

(a) all Existing Generating Capacity Resources,

(b) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,

(c) Import Capacity Resources cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period, and

(d) Existing Demand Resources that are qualified to participate in the Forward Capacity Market and New Demand Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period and Other Demand Resources in existence during the ICAP Transition Period,

but shall exclude:

(a) capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period, and

(b) resources for which Permanent De-list Bids cleared in previous Forward Capacity Auctions.

The rating of Existing Generating Capacity Resources and Existing Import Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements and Maximum Capacity Limits shall be the summer Qualified Capacity value of such resources for the relevant Load Zone. The rating of Demand Resources and Other Demand Resources shall be the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value. The rating of resources, except for Demand Resources, cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period shall be based on the amount of Qualified Capacity that cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period. Resources are located within the Load Zones in which they are electrically located as determined during the qualification process.

III.12.7.2.1 Special Transition Rule Regarding the Reserve Margin Adjustment Factor. Notwithstanding any other provision of this Market Rule, on or after January 1, 2009, the Installed Capacity Requirement, Local Sourcing Requirements and Maximum Capacity Limits for any Forward Capacity Auction or reconfiguration auction will be adjusted to reflect any effective over-rating of capacity associated with the application of a reserve margin adjustment factor to the Qualified Capacity of Demand Resources or to any Existing Import Capacity Resource.

III.12.7.3 Resource Availability. The Installed Capacity Requirement and the Local Sourcing Requirements shall be calculated taking resource availability into account and shall be determined as follows:

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement and the Local Sourcing Requirements until the ISO determines that the use of weighted EFORd, pursuant to subsection (b) is appropriate.

(b) Once sufficient data are collected during the ICAP Transition Period, use of weighted EFORd as a transition metric between EFORd and the process for measuring availability in the Forward Capacity Market shall be evaluated and included in the calculation of the Installed Capacity Requirement and the Local Sourcing Requirements.

(c) Once sufficient data are collected under the availability incentives in the Forward Capacity Market, a resource availability metric, which reflects resource availability in a manner that is consistent with the availability incentives in the Forward Capacity Market, shall be developed and reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies and used in the calculation of the Installed Capacity Requirement and the Local Sourcing Requirements.

For resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that do not have sufficient data to calculate an availability metric as defined in subsections (a), (b) or (c) above, class average data for similar resource types shall be used.

For Demand Resources and Other Demand Resources in existence during the ICAP Transition Period, historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement and Local Sourcing Requirements.

III.12.7.4 Load and Capacity Relief. Load and capacity relief expected from system-wide implementation of the following actions during a capacity deficiency (Operating Procedure No. 4) shall be included in the calculation of the Installed Capacity Requirement and the Local Sourcing Requirements. The Installed Capacity Requirements and Local Sourcing Requirements shall reflect the impact of the following actions during a capacity deficiency which are specified in the ISO New England Manuals and ISO New England Administrative Procedures:

(a) **Implement voltage reduction**. The MW value of the load relief shall be equal to the percentage load reduction achieved in the most applicable voltage reduction tests multiplied by the forecasted seasonal peak loads.

(b) **Arrange for available Emergency energy from Market Participants or neighboring Control Areas**. These actions are included in the calculation through the use of tie benefits to meet system needs. The MW value of tie benefits is calculated in accordance with Section III.12.9.

(c) **Maintain an adequate amount of ten-minute synchronized reserves**. The amount of system reserves included in the Installed Capacity Requirement shall be consistent with those needed for reliable system operations during Emergency Conditions. When modeling transmission constraints, the reserve requirement for a Load Zone shall be the Load Zone's pro rata share of the forecasted system peak load multiplied by the system reserves needed for reliable system operations during Emergency Conditions.

III.12.8 Load Modeling Assumptions. The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias.

Demand Resources and Other Demand Resources in existence during the ICAP Transition Period shall be reflected in the load forecast as specified below:

(a) Expected reductions from an installed or forecast Demand Resource not qualifying for or not participating in the Forward Capacity Auction and Other Demand Resources in existence during the ICAP Transition Period not qualifying for or not participating in the Forward Capacity Auction shall be reflected as a reduction in the load forecast and resultant Installed Capacity Requirement for the relevant Capacity Commitment Period. The expected reduction from these resources will be included in the load forecast to the extent that they meet the qualification process rules, including monitoring and verification plan and financial assurance requirements. If no qualification process rules are in place for the expected reductions from these resources, they shall not be included within the load forecast.

(b) Expected reductions from an installed or forecast Demand Resource that qualifies to participate in the Forward Capacity Market, participates but does not clear in the Forward Capacity Auction, or has cleared in a previous Forward Capacity Auction and is expected to continue in the Forward Capacity Market shall not be reflected as a reduction in the load forecast and the resultant Installed Capacity Requirement for the relevant Capacity Commitment Period.

(c) Expected reductions from an installed or forecast Other Demand Resource in existence during the ICAP Transition Period that qualifies to participate in the Forward Capacity Market, participates but does not clear in the Forward Capacity Auction, or has cleared in a previous Forward Capacity Auction and is expected to continue in the Forward Capacity Market shall not be reflected as a reduction in the load forecast and the resultant Installed Capacity Requirement for the relevant Capacity Commitment Period.

(d) Any realized Demand Resource reductions in the historical period that received Forward Capacity Market payments for these reductions or Other Demand Resources in existence during the ICAP Transition Period that received capacity payments for demand reductions, or Demand Resource reductions and Other Demand Resources reductions that are expected to receive Forward Capacity Market payments by participating in the upcoming Forward Capacity Auction or having cleared in a previous Forward Capacity Auction, shall be added back into the appropriate historical loads to ensure that such resources are not reflected as a reduction in the load forecast and the resultant Installed Capacity Requirement for the relevant Capacity Commitment Period.

For the purposes of subsections (b), (c), and (d), the capacity value of the Demand Resources and Other Demand Resources in existence during the ICAP Transition Period included in the calculation of the Installed Capacity Requirement and the Local Sourcing Requirements shall be the value prescribed in Section III.12.7.2.

III.12.9 Tie Benefits. The Installed Capacity Requirement, the Local Sourcing Requirements and Maximum Capacity Limits shall be calculated assuming appropriate tie benefits, if any, available from interconnections with adjacent Control Areas with which agreements providing for emergency support are in effect between the ISO and that adjacent Control Area, including but not limited to inter-Control Area coordination agreements, emergency aid agreements and the NPCC Regional Reliability Plan.

The ISO shall calculate tie benefits, using a probabilistic multi-area reliability model. The method of calculating the tie benefits associated with the interconnections between the New England Control Area and adjacent Control Areas shall be based on the LOLE calculated before and after interconnecting the New England Control Area to the surrounding Control Areas. The tie benefits, if any, shall be quantified using firm capacity equivalents, where the addition of the firm capacity equivalents results in the LOLE of the isolated New England Control Area being equal to the LOLE of the interconnected New England Control Area.

At least once every three years, the ISO shall perform a tie benefits study and document the results and procedures for calculating the tie benefits in a published report. Results of the tie benefits study shall provide a single overall tie benefit value, reflecting the total tie benefits available from all interconnections with adjacent Control Areas, which can be used in determining the Installed Capacity Requirement. The results of the most recent tie benefits study shall be reviewed by the ISO annually; and the results shall be updated if the ISO determines that New England Control Area or external Control Area system conditions may change the results from the study.

The ISO shall calculate tie benefits using "at-criteria" assumptions for purposes of modeling the adjacent Control Areas, except that when calculating the Installed Capacity Requirement, the Local Sourcing Requirements and Maximum Capacity Limits for use in the annual reconfiguration auction closest to the relevant Capacity Commitment Period, the ISO shall calculate tie benefits using "as-is" data for the purposes of modeling the adjacent Control Areas. If, pursuant to this Section III.12.9, tie benefits are determined to be different at the time of a subsequent reconfiguration auction than assumed in the Forward Capacity Auction, the total amount of tie benefits assumed available over the interface may be limited, if and as necessary, to the assumed interface limit minus any Import Capacity Resources obligated for the relevant Capacity Commitment Period in prior auctions.

III.12.9.1 Individual Control Area Contributions to the Total Tie Benefits. The contribution of an external Control Area directly connected to the New England Control Area to the total amount of tie benefits, as determined in accordance with Section III.12.9, shall be determined based on the LOLE calculated before and after removing the direct interconnections between New England and the target external Control Area used to calculate the total amount of tie benefits as specified in Section III.12.9. The tie benefits from the target Control Area, if any, shall be the amount of firm capacity equivalents needed in the New England Control Area to bring the New England Control Area LOLE, without the New England interconnections with the target Control Area included in the interconnected system, equal to the New England Control Area LOLE with the interconnections with the target Control Area included in the interconnected system. If the sum of the tie benefits from the individual external Control Areas directly connected to the New England Control Area is not equal to the total amount of tie benefits as determined in accordance with Section III.12.9, then each of the Control Area's tie benefits will be adjusted based on the ratio of the individual Control Area tie benefit to the sum of the tie benefits times the total tie benefits as determined in accordance with Section III.12.9. The contributions to the tie benefits from each Control Area directly connected to the New England Control Area shall be used in the calculation of the Local Sourcing Requirements and Maximum Capacity Limits.

III.12.9.2 Tie Benefits Over the HQ Phase I/II HVDC-TF. The tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1 shall be allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.

III.12.10 Calculating the Maximum Amount of Import Capacity Resources that May be Cleared Over External Interfaces in the Forward Capacity Auction and Reconfiguration Auctions. For external interfaces, Import Capacity Resources shall be allowed in the Forward Capacity Auction and reconfiguration auctions up to the interface limit minus the tie benefits, calculated pursuant to Section III.12.9.1 or 12.9.2 over the applicable interface.