



April 1, 2010

VIA HAND DELIVERY

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

**Re: ISO New England Inc. and New England Power Pool,
Docket No. ER10- -000; FCM Conforming Changes to Market Rule 1**

Dear Secretary Bose and Deputy Secretary Davis:

Pursuant to Section 205 of the Federal Power Act,¹ ISO New England Inc. (the “ISO”) and the New England Power Pool (“NEPOOL”) Participants Committee² (together, the “Filing Parties”) hereby jointly submit an original and five copies of this transmittal letter and revised tariff sheets that remove or relocate the ICAP Transition Period rules in Market Rule 1 and make related conforming changes in preparation for the commencement of the first Capacity Commitment Period of the Forward Capacity Market (“FCM”) on June 1, 2010 (the “FCM Conforming Revisions”). In support of the FCM Conforming Revisions, this filing also includes the testimony of Janine Dombrowski, Principal Market Design Analyst in the Market Development department with the ISO, which is sponsored solely by the ISO (the “Dombrowski Testimony”).

The Filing Parties request that the FCM Conforming Revisions become effective June 1, 2010 to coincide with the effectiveness of a number of other tariff changes associated with the termination of the ICAP Transition Period and the beginning of the first FCM Capacity Commitment Period.

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

² Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (“ISO Tariff”), the Second Restated New England Power Pool Agreement, and the Participants Agreement. Market Rule 1 is Section III of the ISO Tariff.

I. DESCRIPTION OF THE FILING PARTIES; COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization (“RTO”) for New England. The ISO operates the New England bulk power system and administers New England’s organized wholesale electricity market pursuant to the ISO Tariff and the Transmission Operating Agreement with the New England transmission owners. In its capacity as an RTO, the ISO also has the objective to assure that the bulk power supply system within the New England Control Area conforms to proper standards of reliability as established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 410 members. The Participants include all of the electric utilities rendering or receiving services under the ISO Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission in *ISO New England Inc. et al.*, 109 FERC ¶ 61,147 (2004), the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, “NEPOOL provide[s] the sole Participant Process for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the [ISO] Tariff, [Transmission Operating Agreement] and the Market Participant Services Agreement included in the [ISO] Tariff.”

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

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II. STANDARD OF REVIEW

The instant revisions are submitted pursuant to Section 205 of the Federal Power Act, which “gives a utility the right to file rates and terms for services rendered with its assets.”⁴ Under Section 205, the Commission “plays ‘an essentially passive and reactive’ role”⁵ whereby it “can reject [a filing] only if it finds that the changes proposed by the public utility are not ‘just and reasonable.’”⁶ The Commission limits this inquiry “into whether the rates proposed by a utility are reasonable -- and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs.”⁷ The revision “need not be the only reasonable methodology, or even the most accurate.”⁸ As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.⁹

III. RATIONALE FOR THE FCM CONFORMING CHANGES

The ICAP Transition Period began on December 1, 2006 and ends with the commencement of the first Capacity Commitment Period of the Forward Capacity Market on

³ Due to the joint nature of this filing, the Filing Parties respectfully request a waiver of Section 385.203 of the Commission’s regulations to allow the inclusion of more than two persons on the service list in this proceeding.

⁴ *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002).

⁵ *Id.* at 10 (quoting *City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

⁶ *Id.*

⁷ *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

⁸ *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

⁹ *Cf. Southern California Edison Co., et al.*, 73 FERC ¶ 61,219 at 61,608 n.73 (1995) (“Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters.” (citing *City of Bethany*, 727 F.2d at 1136)).

June 1, 2010. During the ICAP Transition Period, Market Participants can qualify for ICAP Payments for making available to New England the capacity of a qualifying resource under the requirements set forth in Section III.8 of Market Rule 1. Section III.8 contains the majority of market rules pertaining to the ICAP Transition Period, including eligibility rules, capacity value rules, and payment and cost allocation rules.

With the commencement of the first Capacity Commitment Period on June 1, 2010, the large majority of ICAP Transition Period rules are no longer applicable, and therefore must be removed from Market Rule 1. Where applicable, some of the ICAP Transition Period rules must be relocated to other sections of the market rules. The commencement of the first FCM Capacity Commitment Period is also prompting other minor changes to Market Rule 1 to ensure the terminology used throughout Market Rule 1 conforms to the terminology of the Forward Capacity Market, as well as to ensure that capacity resource offer and scheduling requirements that are specified outside of the primary Forward Capacity Market rule provisions accurately reflect the requirements for capacity resources in the Forward Capacity Market.

IV. DESCRIPTION OF THE FCM CONFORMING REVISIONS

The FCM Conforming Revisions are necessary and important changes that support the ISO's administration of the New England Markets. With the completion of the ICAP Transition Period and commencement of the first FCM Capacity Commitment Period on June 1, 2010, the market rules pertaining to installed capacity during the ICAP Transition Period must be removed, relocated or revised to indicate how those requirements apply under the Forward Capacity Market construct. The FCM Conforming Revisions, as further explained in the Dombrowski Testimony, accomplish these objectives, in large part, by removing Section III.8 of Market Rule 1, which contains the majority of the operative provisions regarding installed capacity during the ICAP Transition Period. The provisions in Section III.8 that are still relevant and necessary have been relocated to the appropriate places in Market Rule 1. The FCM Conforming Revisions also update and modify other relevant provisions of Market Rule 1. Specifically, the FCM Conforming Revisions accomplish the following:

- **Update Terminology:** The revisions replace references to "ICAP Resource" and other ICAP Transition Period-specific terminology with the corresponding terms applicable for the Forward Capacity Market. Page 3 of the Dombrowski Testimony details this change.
- **Remove Transition Period-Specific Rules from Market Rule 1:** The revisions remove energy offer requirements, resource scheduling requirements and other similar requirements in Sections III.1 through III.6 of Market Rule 1 that are specific to the ICAP Transition Period. Pages 4 through 6 of the Dombrowski Testimony detail each of these changes.
- **Remove or Relocate Rules in Section III.8 of Market Rule 1:** The revisions remove or, where applicable, relocate the ICAP Transition Period market rules in Section III.8 of Market Rule 1. More specifically, the payment and eligibility

rules in Sections III.8.1, III.8.2 and III.8.3 are being removed because they are superseded by provisions in Section III.13 of Market Rule 1 regarding payment and eligibility for the Forward Capacity Market. Provisions in Section III.8.1 and III.8.3 pertaining to the treatment of Dispatchable Asset Related Demand are being moved to Section III.13.7.3.1.3 and to a new Section III.1.10.6 in order to preserve the current treatment of these resources following the end of the ICAP Transition Period. Provisions in Section III.8.3.6.2 pertaining to Other Demand Resource projects during the ICAP Transition Period are being removed because these resources are not recognized as a distinct resource type in the Forward Capacity Market construct. A number of changes pertaining to capacity imports are being filed in light of the differences in the treatment of these resources during the ICAP Transition Period and for the Forward Capacity Market. Pages 6 through 8 of the Dombrowski Testimony provide additional details regarding these revisions.

- Eliminate Redundancy: The remaining provisions in Section III.8 (pertaining to outage scheduling, operating data submission, sanctioning, de-listing capacity resources, calculation of capacity ratings, and ICAP Payment cost allocation) are all addressed to the extent required under the Forward Capacity Market construct in Section III.13 and therefore the associated Section III.8 rules will no longer be necessary after May 31, 2010. Pages 8 through 9 of the Dombrowski Testimony provide additional details regarding these changes.
- Distinguish the Retirement of Capacity Resources: Section III.12.6(a)(i) addresses the issue of which generating units will be included in the modeling assumptions used in determining the network model that is employed for purposes of calculating the Installed Capacity Requirement. This Section is being revised to reflect that, under the Forward Capacity Market design, capacity resource retirement determinations are made in accordance with the FCM retirement provisions in Section III.13.2.5.2.5.3 rather than the general generating resource retirement provisions in Section I.3.9 and Section II.47 of the ISO Tariff. The current version of Section I.3.9 makes clear that Section III.13.2.5.2.5.3 governs retirement determinations for capacity resources. Page 10 of the Dombrowski Testimony details this change.

By removing and, where appropriate, relocating the ICAP Transition Period market rules and completing the other conforming changes proposed herein, the FCM Conforming Revisions help to avoid ambiguity in Market Rule 1 about the application of the current capacity market rules once the first Capacity Commitment Period of the Forward Capacity Market has begun. These changes are, therefore, just and reasonable and support the ISO's administration of the New England Markets.

V. STAKEHOLDER PROCESS

The NEPOOL Markets Committee, at its January 12-13, 2010 meeting, voted unanimously to recommend NEPOOL Participants Committee support for the FCM Conforming Revisions to Section III.1-III.11 and III.13 of Market Rule 1. The NEPOOL Reliability Committee, at its January 28, 2010 meeting, voted unanimously to recommend NEPOOL Participants Committee support for FCM Conforming Revisions to Section III.12 of Market Rule 1. At its February 5, 2010 meeting, the NEPOOL Participants Committee also voted unanimously to support the FCM Conforming Revisions as part of its Consent Agenda, with only one abstention noted.¹⁰

VI. REQUESTED EFFECTIVE DATE AND ORDER ISSUANCE

The Filing Parties request an effective date of June 1, 2010 for the FCM Conforming Revisions.

VII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates.¹¹ However, the FCM Conforming Revisions are not traditional "rates," and the Filing Parties are not traditional investor-owned utilities. In light of these circumstances, the Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13, and request a waiver of Section 35.13 of the Commission's regulations to the extent the content or form deviates from the specific technical requirements of the regulations.

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

- ♦ This transmittal letter;
- ♦ Blacklined Tariff Sheets reflecting the revisions submitted in this filing (Attachment 1);

¹⁰ The Consent Agenda for a Participants Committee meeting, similar to the Consent Agenda for a Commission open meeting, is a group of actions (each recommended by a Technical Committee or subgroup established by the Participants Committee) to be taken by the Participants Committee through approval of a single motion at a meeting. All recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. The Participants Committee's approval of the February 5, 2010 Consent Agenda included its support for the FCM Conforming Revisions.

¹¹ 18 C.F.R. § 35.13 (2009).

- ♦ Clean Revised Tariff Sheets reflecting the revisions submitted in this filing (Attachment 2);
- ♦ Testimony of Janine Dombrowski, Principal Market Design Analyst in Market Development, sponsored solely by the ISO (Attachment 3); and
- ♦ List of governors, utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and other entities, to which a copy of this filing has been sent (Attachment 4).

35.13(b)(2) - The Filing Parties request that the revisions become effective June 1, 2010.

35.13(b)(3) - Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at http://www.iso-ne.com/regulatory/ferc/nepool/gov_ptcpnts_eserved.pdf. A copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, the New England Conference of Public Utility Commissioners, Inc., and to the New England States Committee on Electricity. Their names and addresses are shown in Attachment 4. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified on Attachment 4 to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

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

35.13(b)(5) - The reasons for this filing are discussed in Sections III and IV of this transmittal letter.

35.13(b)(6) - The ISO's approval of the revision is evidenced by this filing. With respect to NEPOOL's approval, as noted in Section V of this transmittal letter, these changes reflect the support of the Participant Processes required by the Participants Agreement, having been unanimously approved by the NEPOOL Participants Committee as described in Section V of this transmittal letter.

35.13(b)(7) - The Filing Parties do not have knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

VIII. CONCLUSION

For the reasons stated herein, the Filing Parties respectfully request that the Commission accept the FCM Conforming Revisions as filed, without condition, suspension, or hearing, to be effective June 1, 2010.

Please acknowledge receipt of the foregoing by date-stamping the enclosed extra copies of this filing and returning them to the courier delivering this filing.

Respectfully submitted,

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Attachment 1

Capacity Value, for purposes of the ICAP Transition Period, means the value (in kW-month) of an Other Demand Resource for a month that is equal to its Demand Reduction Value in that month multiplied by 1.08, as described in Section III.8.8.5.2.1 of Market Rule 1. For purposes of the Forward Capacity Market, **Capacity Value** means the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.7.1.5 of Market Rule 1.

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

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

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

Charge is defined in the ISO New England Billing Policy.

CLAIM10 is the generation output level, expressed in MW, which can be reached by a Resource (from an off-line state) within 10 minutes after receiving a Dispatch Instruction or the amount of reduced consumption, expressed in MW, which can be reached by a Dispatchable Asset Related Demand within 10 minutes after receiving a Dispatch Instruction. A CLAIM10 value is required as part of a Resource's or Dispatchable Asset Related Demand's Offer Data. CLAIM10 values are established pursuant to the provisions of Section III.9.5.2.

CLAIM30 is the generation output level, expressed in MW, which can be reached by a Resource (from an off-line state) within 30 minutes after receiving a Dispatch Instruction or the amount of reduced consumption, expressed in MW, which can be reached by a Dispatchable Asset Related Demand within 30 minutes after receiving a Dispatch Instruction. A CLAIM30 value is required as part of a Resource's or Dispatchable Asset Related Demand's Offer Data. CLAIM30 values are established pursuant to the provisions of Section III.9.5.2.

~~CLAIM30 is the generation output level, expressed in MW, which can be reached by a Resource (from an off-line state) within 30 minutes after receiving a Dispatch Instruction or the amount of reduced consumption, expressed in MW, which can be reached by a Dispatchable Asset Related Demand within 30 minutes after receiving a Dispatch Instruction. A CLAIM30 value is required as part of a Resource's or Dispatchable Asset Related Demand's Offer Data. CLAIM30 values are established pursuant to the provisions of Section III.9.5.2.~~

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

Commission is the Federal Energy Regulatory Commission.

Commitment Offer Test is defined in Section III.A.5.8.3 of *Appendix A* of Market Rule 1.

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

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

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

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion

is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the Dispatch Day in the Day-Ahead Market or Real-Time Market.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and/or Secondary FTR Market (as the latter two terms are defined in Section III of the Tariff) and that does not participate in other markets or programs of the New England Markets, *provided, however,* that an FTR-Only Customer may also be a DRP-Only Customer and/or an ODR-Only Customer. References in this Tariff to a “Non-Market Participant FTR Customers” and similar phrases shall be deemed references to an FTR-Only Customer

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

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

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

Generator Forced Outage means an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the ISO New England Manuals and ISO New England Administrative Procedures. A reduction in output to zero of an available generating unit ~~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.

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

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

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

Merchant Transmission Owner (MTO) is an owner of MTF that is a signatory to an MTOA with the ISO.

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

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

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

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

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

~~**UCAP Peak Contribution** is a Market Participant's share of the New England Control Area coincident peak for the prior calendar year as determined prior to the start of each power year. Daily UCAP Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.~~

UCS is Unit Commitment Software as more fully defined in Section III.A.5.5.3 of Appendix A of Market Rule 1.

UDS is Unit Dispatch System Software, as more fully defined in Section III.A.5.5.3 of Appendix A of Market Rule 1.

Unforced Capacity (UCAP) is a MW amount of installed capacity of a Resource or a region that has been adjusted to account for availability.

Unforced Capacity Rating (UCAP Rating) means the MW amount of capacity for which an ICAP Resource, other than a Dispatchable Asset Related Demand Resource, will receive ICAP Payments, as described in Section III.8 of Market Rule 1.

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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 with a Capacity Supply Obligation available for dispatch

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

upon Congestion Costs not exceeding a specified level.
Market Participants whose purchases and sales and
External Transactions are scheduled in the Day-Ahead
Energy Market shall be obligated to purchase or sell energy
or pay Congestion Costs and costs for losses, at the
applicable Day-Ahead Prices for the amounts scheduled.

- (c) In the Real-Time Energy Market,
- (i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Prices~~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.

- (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 ~~selling~~ 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 without a Capacity Supply Obligation 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. AllThe foregoing Supply Offers and Demand Bids for ICAP Resources, as applicable and non ICAP Resources:~~

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 with a Capacity Supply Obligation 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

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

- (a) [Reserved.]
- (b) The offered prices of Resources or portions of Resources that are Self-Scheduled, or otherwise not following the dispatch orders of the ISO, shall not be considered by the ISO in determining Locational Marginal Prices.
- (c) A Market Participant with a Resource that does not have a Capacity Supply Obligation shall comply with the requirements in Section III.13.6.2 when Self-Scheduling any portion of that Resource. ~~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.~~ [Reserved.]

~~(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~~

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~~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.1.10.6 Dispatchable Asset Related Demand Resources.~~[Reserved.]~~

External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demand Resources. Except as noted below with respect to a pumped storage generator that does not have a Capacity Supply Obligation, a Dispatchable Asset Related Demand Resource in the New England Control Area must:

- (a) each day, either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 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;

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~~

- (e) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;
- (f) abide by the ISO maintenance coordination procedures;
- (g) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand Resource; and
- (h) comply with the ISO New England Manuals.

To schedule the dispatchable pumping demand of a pumped storage generator that does not have a Capacity Supply Obligation, a Market Participant must comply with the requirements in (b) through (h) for the applicable Operating Day and must either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule that specifies the prices at which the Resource is willing to consume energy for the applicable Operating Day.

~~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.~~

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 on an external interface where advance transmission reservations are required must comply with the requirements in Section III.13.6.1.2.1 with respect to linking~~link~~ the transaction to the associated NERC E-Tag ~~and transmission reservation and NERC E-Tag, 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.~~

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~~(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.~~

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 consistent with the ISO New England Manuals and ISO New England Administrative Procedures, ~~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.~~

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 the dispatchable increments from resources~~generation increments from ICAP Resources~~ the remaining increments of which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall ensure that the entity controlling a Pool-Scheduled Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

- (d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to ~~dispatched~~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 External Transaction sales out of the New England Control Area that are not backed by a~~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.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 CoincidentUCAP Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions. The ISO will accept revisions to asset specific meter data, daily Coincident~~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, Forward Capacity Market~~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 Coincident~~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

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 CoincidentUCAP Peak Contribution values, the average of the daily Meter Data Errors involving CoincidentUCAP Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

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

Metered Assets prior to the 46th calendar day after the Meter Data Error RBA Submission Limit. Corrected metered data for Profiled Load Assets and Coincident~~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

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 External Transactions Resources that are not associated with Import Capacity/ICAP Resources. The ISO shall select offers to sell

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.8 ~~[Reserved.]~~ 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.~~

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III.8.1 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.8.2 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.8.2.1 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.8.2.2 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.~~

III.8.2.3 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.8.2.4 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.8.2.5 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.8.2.6 Demand Resources.

III.8.2.6.1 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.8.2.6.2 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.8.2.6.2.1 Types of ODRs.

III.8.2.6.2.1.1 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.8.2.6.2.1.2 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.8.2.6.2.1.3 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

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.8.2.6.2.2 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.8.2.6.2.3 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.8.2.6.2.4 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.8.2.7 ICAP Import Contracts.

III.8.2.7.1 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.8.2.7.2 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.8.2.7.2.1 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.8.2.7.2.2 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.8.2.7.3 Failure of ICAP Import Contract to Offer or Deliver.

III.8.2.7.3.1 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.8.2.7.3.1.1 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.8.2.7.3.1.2 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, 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.8.2.7.3.1.3 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.8.2.7.3.2 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.8.2.7.3.3 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.8.3 ICAP Resource Outage Scheduling Provisions:

III.8.3.1 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.8.3.2 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.8.4 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.8.4.1 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.8.4.2 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.8.5 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.8.6 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.8.6.1 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.8.6.2 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.8.6.3De-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.8.7 UCAP Ratings. A UCAP Rating, in MW, will be determined for each ICAP Resource as described below:

III.8.7.1 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.8.7.1.1 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: <ul style="list-style-type: none">•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.8.7.1.2Phase 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.8.7.1.3 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.8.7.2 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.8.7.3 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.8.7.4 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.8.7.5 Demand Resources UCAP Ratings.

III.8.7.5.1 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.8.7.5.2 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.8.5.2.1, multiplied by the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO.

III.8.7.5.2.1 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.8.7.6 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	20.9	10/31/2003
NYPA: NY—NE: MMWEC	81.8	10/31/2003
NYPA: NY—NE: Paseoag	2.4	10/31/2003
NYPA: NY—NE: VELCO	15.0	10/31/2003
	120.1	
VJO: Highgate—NE	Up to 225*	2020
VJO: Phase I/II—NE	Up to 110*	
VJO: CCC Block Load	Up to 60*	
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.8.8ICAP 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.8.8.1Calculation 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.8.8.2 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.8.8.3 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.~~

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

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 ~~same manner as fixed cost charges associated with Local Second Contingency Protection Resources under Section III.6.4.4(c) of this Market Rule.~~

Issued by: ~~Raymond W. Hepper~~^{Kathleen A. Carrigan}, Effective: ~~June 1, 2010~~^{With notice, on or after October 1, 2006}
~~Senior Vice President and General Counsel~~
Issued on: ~~April 1, 2010~~^{February 6, 2006}

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 ~~resources~~ generating units that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Section III.13.2.5.2.5.3 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.13.1.3.5.1. Documentation of Import. For each New Import Capacity Resource, the Market Participant submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the entire Capacity Commitment Period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iv) documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load. For each New Import Capacity Resource, the Market Participant must specify the interface over which the capacity will be imported.

III.13.6.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals and this Market Rule;
- (c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.1.2. Import Capacity Resources.

III.13.6.1.2.1. Energy Market Offer Requirements. A Market Participant must offer energy associated with an Import Capacity Resource with a Capacity Supply Obligation into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions for every hour of each Operating Day at the same external interface totaling an amount (MW) equal to the Capacity Supply Obligation unless the Import Capacity Resource is associated with an External Resource that is on an outage. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with this requirement may be subject to sanctions pursuant to Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.2 for failing to deliver the

- (c) Submittal of External Transactions to the Day-Ahead Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource requires submittal of matching energy transactions to the Real-Time Energy Market; the External Transactions submitted to the Real-Time Energy Market must match the External Transactions submitted to the Day-Ahead Energy Market, subject to the right to submit different prices into the Real-Time Energy Market.
- (d) External Transactions submitted to the Real-Time Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource must be submitted prior to noon the day before the Operating Day for which they are intended to be scheduled.
- (e) A Market Participant submitting a priced External Transaction supporting an Import Capacity Resource with a Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must link the transaction to the associated transmission reservation and NERC E-Tag no later than one hour before the Operating Hour in order to be eligible for scheduling in the Real-Time Energy Market. If a Market Participant does not link the transaction to the associated transmission reservation and NERC E-Tag in the Real-Time Energy Market for any hour during which the External Transaction would otherwise have been economically and reliably scheduled in the Real-Time Energy Market, the associated Import Capacity Resource shall be treated as

having not delivered energy for the hour despite ISO requested dispatch under Section III.13.7.1.2 and III.13.7.2.7.2. A Market Participant submitting any other External Transaction to the Real-Time Energy Market must comply with the requirements in Section III.1.10.7(e) with respect to linking the transaction to the associated transmission reservation and NERC E-Tag.

III.13.6.1.2.2. Additional Requirements for Import Capacity Resources. Import Capacity Resources are subject to the following additional requirements:

- (a) information submittal requirements for External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals;
- (b) resource backed Import Capacity Resources shall be subject to the outage requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures. Control Area backed Import Capacity Resources are not subject to such outage requirements;
- (c) resource backed Import Capacity Resources are subject to the voluntary and mandatory re-scheduling of maintenance procedures outlined in the ISO New England Operating Procedures and ISO New England Manuals.
- (d) at the time of submittal, each External Transaction shall reference the associated Import Capacity Resource.

III.13.6.1.3. Intermittent Power Resources.

III.13.6.1.3.1. Energy Market Offer Requirements.

Intermittent Power Resources may submit offers into the Day-Ahead Energy Market. Such resources are required to submit offers for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

- (a) auditing and rating requirements as detailed in the ISO New England Manuals;
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals;
- (c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.1.4.1. Energy Market Offer Requirements.

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.4.2. Additional Requirements for Settlement Only Resources. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources having a Capacity Supply Obligation are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals;

- (b) Operating Data collection requirements as detailed in the ISO New England Manuals;
- (c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.5. Demand Resources. Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Markets.

III.13.6.1.5.1. Additional Requirements for Demand Resources. Demand Resources shall comply with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.6.1.5.2. Reporting of Forecast Hourly Demand Reduction. A Market Participant with Critical Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO a two-day forecast of each Demand Resource's Forecast Hourly Demand Reduction for each Operating Day. The Market Participant shall update its forecast, in accordance with the ISO New England Manuals and Operating Procedures, to reflect its estimate of each Demand Resource's Forecast Hourly Demand Reduction.

III.13.6.1.5.3. Reporting of Monthly Maximum Forecast Hourly Demand Reduction. A Market Participant with Critical Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO each month a forecast of each resource's monthly maximum Forecast Hourly Demand Reduction for each of the next 12 months.

III.13.6.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation. Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

- (a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;
- (b) complying with the ~~Operating~~ Data collection requirements detailed in the ISO New England Manuals; and
- (c) complying with outage requirements

III.13.6.2.3. Intermittent Power Resources.

III.13.6.2.3.1. Energy Market Offer Requirements. An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.3.2. Additional Requirements for Intermittent Power Resources. Intermittent Power Resources are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals; and
- (b) ~~Q~~^Operating ~~D~~^Data collection requirements as detailed in the ISO New England Manuals.

III.13.6.2.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.2.4.1. Energy Market Offer Requirements. A Settlement Only Resource may not submit an offer into the Day-Ahead Energy Market or the Real-Time Energy Market.

III.13.6.2.4.2. Additional Requirements for Settlement Only Resources. Settlement Only Resources are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals;
- (b) ~~Q~~^Operating ~~D~~^Data collection requirements as detailed in the ISO New England Manuals;
- (c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.2.5. Demand Resources. Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.3. Exporting Resources. A resource that is exporting capacity not subject to a Capacity Supply Obligation to an external Control Area shall comply with this Section III.13.6.3 and the ISO New England Manuals. Intermittent Power Resources, Settlement Only Resources, and Demand Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7.

III.13.6.4. ISO Requests for Energy. The ISO may request that a Generating Capacity Resource having capacity that is not subject to a Capacity Supply Obligation provide energy for reliability purposes in the Real-Time Energy Market, but such resource shall not be obligated under Section III.13 of this Tariff by such a request to provide energy from that capacity, and shall not be

calendar year ending December 31 of the second year prior to the start of the upcoming Capability Year. The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: Load associated with pumping of pumped hydro generators, if the resource was pumping; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; and Transmission losses associated with delivery of energy over the Control Area tie lines.

A load serving entity's Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the Capacity Zone's Capacity Requirement as calculated above and (ii) the ratio of the sum of the load serving entity's annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year ending December 31 of the year prior to the start of the upcoming Capability Year to the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year ending December 31 of the year prior to the start of the upcoming Capability Year.

A load serving entity's Capacity Load Obligation shall be its Capacity Requirement, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supply FCA Resource designations. A Capacity Load Obligation can be a positive or negative value. A Market Participant that is not a load serving entity shall have a Capacity Load Obligation equal to the net obligation resulting from Capacity Load Obligation Bilaterals, HQICC, and Self-Supply FCA Resource designations.

A Demand Resource's Demand Reduction Value will not be reconstituted into the load of the Demand Resource for the Obligation Months in the first three FCA delivery

periods for the purpose of determining the Capacity Requirement for the load associated with the Demand Resource. Beginning in February 2009, the ISO will evaluate, in consultation with NEPOOL stakeholders and state utility regulatory agencies, the need for a load reconstitution methodology for Demand Resources. The ISO will file its recommendation to institute or not to institute a load reconstitution methodology with the FERC pursuant to Section 205 of the Federal Power Act on or before September 1, 2009.

III.13.7.3.1.1. HQICC Used in the Calculation of Capacity Requirements. In order to treat HQICCs as a load reduction, each holder of HQICCs shall have its Capacity Requirement in the Capacity Zone in which the HQ Phase I/II external node is located as specified in Section III.13.1.3 adjusted by its share of the total monthly HQICC amount.

III.13.7.3.1.2. Charges Associated with Self-Supplied FCA Resources. The capacity associated with a Self-Supplied FCA Resource shall be treated as a credit toward the Capacity Load Obligation of the load serving entity so designated by such resources as described in Section III.13.1.6. The amount of Self-Supplied FCA Resources shall be determined pursuant to Section III.13.1.6.

III.13.7.3.1.3. Charges Associated with Dispatchable Asset Related Demands. Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource.

~~III.13.7.3.2. Excess Revenues.~~ Revenues collected from load serving entities in excess of revenues paid to resources shall be paid to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.3.3.

The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.3.2. Excess Revenues. Revenues collected from load serving entities in excess of revenues paid to resources shall be paid to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.3.3.

III.13.7.3.3. Capacity Transfer Rights.

III.13.7.3.3.1. Definition and Payments to Holders of Capacity Transfer Rights. The ISO shall create Capacity Transfer Rights (“CTRs”) for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and annual reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone’s Net Regional Clearing Price and each Capacity Zone’s Capacity Load Obligations, as calculated in Section III.13.7.3.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity

Attachment 2

Capacity Value, for purposes of the ICAP Transition Period, means the value (in kW-month) of an Other Demand Resource for a month that is equal to its Demand Reduction Value in that month multiplied by 1.08, as described in Section III.8.8.5.2.1 of Market Rule 1. For purposes of the Forward Capacity Market, **Capacity Value** means the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.7.1.5 of Market Rule 1.

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

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

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

Charge is defined in the ISO New England Billing Policy.

CLAIM10 is the generation output level, expressed in MW, which can be reached by a Resource (from an off-line state) within 10 minutes after receiving a Dispatch Instruction or the amount of reduced consumption, expressed in MW, which can be reached by a Dispatchable Asset Related Demand within 10 minutes after receiving a Dispatch Instruction. A CLAIM10 value is required as part of a Resource's or Dispatchable Asset Related Demand's Offer Data. CLAIM10 values are established pursuant to the provisions of Section III.9.5.2.

CLAIM30 is the generation output level, expressed in MW, which can be reached by a Resource (from an off-line state) within 30 minutes after receiving a Dispatch Instruction or the amount of reduced consumption, expressed in MW, which can be reached by a Dispatchable Asset Related Demand within 30 minutes after receiving a Dispatch Instruction. A CLAIM30 value is required as part of a Resource's or Dispatchable Asset Related Demand's Offer Data. CLAIM30 values are established pursuant to the provisions of Section III.9.5.2.

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

Commission is the Federal Energy Regulatory Commission.

Commitment Offer Test is defined in Section III.A.5.8.3 of *Appendix A* of Market Rule 1.

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

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

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

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

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and/or Secondary FTR Market (as the latter two terms are defined in Section III of the Tariff) and that does not participate in other markets or programs of the New England Markets, *provided, however*, that an FTR-Only Customer may also be a DRP-Only Customer and/or an ODR-Only Customer. References in this Tariff to a “Non-Market Participant FTR Customers” and similar phrases shall be deemed references to an FTR-Only Customer

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

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

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

Generator Forced Outage means an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the ISO New England Manuals and ISO New England Administrative Procedures. A reduction in output to zero of an available generating unit that is approved by the ISO shall not constitute a Generator Forced Outage.

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

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

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

Merchant Transmission Owner (MTO) is an owner of MTF that is a signatory to an MTOA with the ISO.

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

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

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

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

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UCS is Unit Commitment Software as more fully defined in Section III.A.5.5.3 of Appendix A of Market Rule 1.

UDS is Unit Dispatch System Software, as more fully defined in Section III.A.5.5.3 of Appendix A of Market Rule 1.

Unforced Capacity (UCAP) is a MW amount of installed capacity of a Resource or a region that has been adjusted to account for availability.

Unforced Capacity Rating (UCAP Rating) means the MW amount of capacity for which an ICAP Resource, other than a Dispatchable Asset Related Demand Resource, will receive ICAP Payments, as described in Section III.8 of Market Rule 1.

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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 resources with a Capacity Supply Obligation available for dispatch

III.1.7.20 Information and Operating Requirements.

- (a) [Reserved.]
- (b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO units that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output 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 all bilateral purchase

upon Congestion Costs not exceeding a specified level.
Market Participants whose purchases and sales and
External Transactions are scheduled in the Day-Ahead
Energy Market shall be obligated to purchase or sell energy
or pay Congestion Costs and costs for losses, at the
applicable Day-Ahead Prices for the amounts scheduled.

- (c) In the Real-Time Energy Market,
- (i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule, 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.

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- (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 selling into the New England Markets, from either internal Resources or External Resources, shall submit Supply Offers or External Transactions for the supply of

energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Regulation, Operating Reserve or other services as applicable, for the following Operating Day. Supply Offers shall be submitted to the ISO in the form specified by the ISO and shall contain the information specified in the ISO's Offer Data specification, as applicable. External Transactions shall be submitted to the ISO according to Section III.1.10.7 of this Market Rule. 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.

Energy offered from generating Resources without a Capacity Supply Obligation shall not be supplied from Resources that are included in or otherwise committed to supply the operating reserve requirements of another Control Area. All Supply Offers and Demand Bids:

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 a resource with a Capacity Supply Obligation shall submit a forecast of the availability of each such resource for the next seven days. A Market Participant 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.
- (g) Each Supply Offer or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until

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

- (a) [Reserved.]
- (b) The offered prices of Resources or portions of Resources that are Self-Scheduled, or otherwise not following the dispatch orders of the ISO, shall not be considered by the ISO in determining Locational Marginal Prices.
- (c) A Market Participant with a Resource that does not have a Capacity Supply Obligation shall comply with the requirements in Section III.13.6.2 when Self-Scheduling any portion of that Resource.

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

III.1.10.4 [Reserved.]

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III.1.10.6 Dispatchable Asset Related Demand Resources. External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demand Resources. Except as noted below with respect to a pumped storage generator that does not have a Capacity Supply Obligation, a Dispatchable Asset Related Demand Resource in the New England Control Area must:

- (a) each day, either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 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;

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- (e) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;
 - (f) abide by the ISO maintenance coordination procedures;
 - (g) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand Resource; and
 - (h) comply with the ISO New England Manuals.

To schedule the dispatchable pumping demand of a pumped storage generator that does not have a Capacity Supply Obligation, a Market Participant must comply with the requirements in (b) through (h) for the applicable Operating Day and must either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule that specifies the prices at which the Resource is willing to consume energy for the applicable Operating Day.

III.1.10.7 External Transactions.

- (a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by 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 Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must comply with the requirements in Section III.13.6.1.2.1 with respect to linking the transaction to the associated transmission reservation and NERC E-Tag. All other External Transactions submitted to the Real-Time Energy Market must contain the associated NERC E-Tag and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

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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 previously designated as Self-Scheduled consistent with the ISO New England Manuals and ISO New England Administrative Procedures.

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

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

- (d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to dispatched output 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 External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

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

III.3.6.3 Data Revisions. The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines for submittal of that data have passed, except as provided in Section III.3.8 of 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, Forward Capacity Market, 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 Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of 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

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

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

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

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

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

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

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 External Transactions that are not associated with Import Capacity Resources. The ISO shall select offers to sell

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.

III.8 [Reserved.]

[Sheet Nos. 7233 through 7276B are reserved for future use.]

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

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.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 resources that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Section III.13.2.5.2.5.3;
 - (ii) all 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.13.1.3.5.1. Documentation of Import. For each New Import Capacity Resource, the Market Participant submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the entire Capacity Commitment Period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iv) documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load. For each New Import Capacity Resource, the Market Participant must specify the interface over which the capacity will be imported.

III.13.6.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals and this Market Rule;
- (c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.1.2. Import Capacity Resources.

III.13.6.1.2.1. Energy Market Offer Requirements. A Market Participant must offer energy associated with an Import Capacity Resource with a Capacity Supply Obligation into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions for every hour of each Operating Day at the same external interface totaling an amount (MW) equal to the Capacity Supply Obligation unless the Import Capacity Resource is associated with an External Resource that is on an outage. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with this requirement may be subject to sanctions pursuant to Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.2 for failing to deliver the

- (c) Submittal of External Transactions to the Day-Ahead Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource requires submittal of matching energy transactions to the Real-Time Energy Market; the External Transactions submitted to the Real-Time Energy Market must match the External Transactions submitted to the Day-Ahead Energy Market, subject to the right to submit different prices into the Real-Time Energy Market.
- (d) External Transactions submitted to the Real-Time Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource must be submitted prior to noon the day before the Operating Day for which they are intended to be scheduled.
- (e) A Market Participant submitting a priced External Transaction supporting an Import Capacity Resource with a Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must link the transaction to the associated transmission reservation and NERC E-Tag no later than one hour before the Operating Hour in order to be eligible for scheduling in the Real-Time Energy Market. If a Market Participant does not link the transaction to the associated transmission reservation and NERC E-Tag in the Real-Time Energy Market for any hour during which the External Transaction would otherwise have been economically and reliably scheduled in the Real-Time Energy Market, the associated Import Capacity Resource shall be treated as

having not delivered energy for the hour despite ISO requested dispatch under Section III.13.7.1.2 and III.13.7.2.7.2. A Market Participant submitting any other External Transaction to the Real-Time Energy Market must comply with the requirements in Section III.1.10.7(e) with respect to linking the transaction to the associated transmission reservation and NERC E-Tag.

III.13.6.1.2.2. Additional Requirements for Import Capacity Resources. Import Capacity Resources are subject to the following additional requirements:

- (a) information submittal requirements for External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals;
- (b) resource backed Import Capacity Resources shall be subject to the outage requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures. Control Area backed Import Capacity Resources are not subject to such outage requirements;
- (c) resource backed Import Capacity Resources are subject to the voluntary and mandatory re-scheduling of maintenance procedures outlined in the ISO New England Operating Procedures and ISO New England Manuals.
- (d) at the time of submittal, each External Transaction shall reference the associated Import Capacity Resource.

III.13.6.1.3. Intermittent Power Resources.

III.13.6.1.3.1. Energy Market Offer Requirements.

Intermittent Power Resources may submit offers into the Day-Ahead Energy Market. Such resources are required to submit offers for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

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- (a) auditing and rating requirements as detailed in the ISO New England Manuals;
 - (b) Operating Data collection requirements as detailed in the ISO New England Manuals;
 - (c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.1.4.1. Energy Market Offer Requirements.

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.4.2. Additional Requirements for Settlement Only Resources. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources having a Capacity Supply Obligation are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals;

- (b) Operating Data collection requirements as detailed in the ISO New England Manuals;
- (c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.5. Demand Resources. Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Markets.

III.13.6.1.5.1. Additional Requirements for Demand Resources. Demand Resources shall comply with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.6.1.5.2. Reporting of Forecast Hourly Demand Reduction. A Market Participant with Critical Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO a two-day forecast of each Demand Resource's Forecast Hourly Demand Reduction for each Operating Day. The Market Participant shall update its forecast, in accordance with the ISO New England Manuals and Operating Procedures, to reflect its estimate of each Demand Resource's Forecast Hourly Demand Reduction.

III.13.6.1.5.3. Reporting of Monthly Maximum Forecast Hourly Demand Reduction. A Market Participant with Critical Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO each month a forecast of each resource's monthly maximum Forecast Hourly Demand Reduction for each of the next 12 months.

III.13.6.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation. Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

- (a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;
- (b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and
- (c) complying with outage requirements

III.13.6.2.3. Intermittent Power Resources.

III.13.6.2.3.1. Energy Market Offer Requirements. An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.3.2. Additional Requirements for Intermittent Power Resources. Intermittent Power Resources are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals; and
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals.

III.13.6.2.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.2.4.1. Energy Market Offer Requirements. A Settlement Only Resource may not submit an offer into the Day-Ahead Energy Market or the Real-Time Energy Market.

III.13.6.2.4.2. Additional Requirements for Settlement Only Resources. Settlement Only Resources are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals;
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals;
- (c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.2.5. Demand Resources. Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.3. Exporting Resources. A resource that is exporting capacity not subject to a Capacity Supply Obligation to an external Control Area shall comply with this Section III.13.6.3 and the ISO New England Manuals. Intermittent Power Resources, Settlement Only Resources, and Demand Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7.

III.13.6.4. ISO Requests for Energy. The ISO may request that a Generating Capacity Resource having capacity that is not subject to a Capacity Supply Obligation provide energy for reliability purposes in the Real-Time Energy Market, but such resource shall not be obligated under Section III.13 of this Tariff by such a request to provide energy from that capacity, and shall not be

calendar year ending December 31 of the second year prior to the start of the upcoming Capability Year. The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: Load associated with pumping of pumped hydro generators, if the resource was pumping; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; and Transmission losses associated with delivery of energy over the Control Area tie lines.

A load serving entity's Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the Capacity Zone's Capacity Requirement as calculated above and (ii) the ratio of the sum of the load serving entity's annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year ending December 31 of the year prior to the start of the upcoming Capability Year to the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year ending December 31 of the year prior to the start of the upcoming Capability Year.

A load serving entity's Capacity Load Obligation shall be its Capacity Requirement, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supply FCA Resource designations. A Capacity Load Obligation can be a positive or negative value. A Market Participant that is not a load serving entity shall have a Capacity Load Obligation equal to the net obligation resulting from Capacity Load Obligation Bilaterals, HQICC, and Self-Supply FCA Resource designations.

A Demand Resource's Demand Reduction Value will not be reconstituted into the load of the Demand Resource for the Obligation Months in the first three FCA delivery

periods for the purpose of determining the Capacity Requirement for the load associated with the Demand Resource. Beginning in February 2009, the ISO will evaluate, in consultation with NEPOOL stakeholders and state utility regulatory agencies, the need for a load reconstitution methodology for Demand Resources. The ISO will file its recommendation to institute or not to institute a load reconstitution methodology with the FERC pursuant to Section 205 of the Federal Power Act on or before September 1, 2009.

III.13.7.3.1.1. HQICC Used in the Calculation of Capacity Requirements. In order to treat HQICCs as a load reduction, each holder of HQICCs shall have its Capacity Requirement in the Capacity Zone in which the HQ Phase I/II external node is located as specified in Section III.13.1.3 adjusted by its share of the total monthly HQICC amount.

III.13.7.3.1.2. Charges Associated with Self-Supplied FCA Resources. The capacity associated with a Self-Supplied FCA Resource shall be treated as a credit toward the Capacity Load Obligation of the load serving entity so designated by such resources as described in Section III.13.1.6. The amount of Self-Supplied FCA Resources shall be determined pursuant to Section III.13.1.6.

III.13.7.3.1.3. Charges Associated with Dispatchable Asset Related Demands. Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource.

Attachment 3

1 UNITED STATES OF AMERICA
2 BEFORE THE
3 FEDERAL ENERGY REGULATORY COMMISSION
4

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6)
7 ISO New England Inc. and)
8 NEPOOL Participants Committee)
9)

Docket No. ER10-___-000

10
11 TESTIMONY OF

12 JANINE DOMBROWSKI

13 I. INTRODUCTION

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

15 A: My name is Janine Dombrowski. I am Principal Market Design Analyst in the
16 Market Development department with ISO New England Inc. (the "ISO"). My
17 business address is One Sullivan Road, Holyoke, Massachusetts 01040.

18 Q: *Please describe your work experience and educational background.*

19 A: I have a Bachelor of Science degree in Physics and a Ph.D. in Resource
20 Economics from the University of Massachusetts - Amherst. I have been
21 with the ISO since 2001. Between 2001 and 2007, I held several positions
22 in the Market Monitoring department including Manager, Emerging
23 Markets, where I was responsible for evaluating new markets and
24 implementing the market monitoring provisions for the Forward Capacity
25 Market. I have worked in Market Development since July 2007,
26 exclusively supporting the Forward Capacity Market design and
27 implementation. During this time I have led the development of Forward
28 Capacity Market design solutions, providing design options and
29 coordinating changes with ISO business owners and New England market

1 participants. I coordinate the ongoing identification and resolution of
2 Forward Capacity Market design issues and supported the changes that are
3 the subject of the instant filing.

4

5 **II. PURPOSE, SCOPE, AND SUMMARY OF TESTIMONY**

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

7 A: The testimony supports a number of revisions to Market Rule 1 to remove the
8 rules pertaining to the ICAP Transition Period and, where appropriate, replace
9 ICAP Transition Period terminology and requirements with terminology and
10 requirements applicable to the Forward Capacity Market.

11 ***Q: Why are these revisions being made at this time?***

12 A: The ICAP Transition Period began on December 1, 2006 and ends with the
13 commencement of the first Capacity Commitment Period of the Forward Capacity
14 Market on June 1, 2010. During the ICAP Transition Period, eligible Market
15 Participants receive ICAP Payments for their resources. Section III.8 of Market
16 Rule 1 contains the majority of market rules pertaining to the ICAP Transition
17 Period, including eligibility rules, capacity value rules, and payment and cost
18 allocation rules. With the commencement of the first Capacity Commitment
19 Period on June 1, 2010, most ICAP Transition Period rules are no longer
20 applicable, and therefore they must be removed from Market Rule 1 or, where
21 applicable, transferred to other sections of the market rules. ICAP Transition
22 Period terminology and requirements in other parts of Market Rule 1 must be
23 removed or revised as well.

1 **Q:** *Please summarize the revisions that the ISO is making to remove the ICAP*
2 *Transition Period rules and otherwise conform the provisions of Market Rule 1*
3 *for the Forward Capacity Market.*

4 **A:** The revisions remove Section III.8 of Market Rule 1, which contains the majority
5 of the operative provisions regarding installed capacity during the ICAP
6 Transition Period, and where necessary relocate required provisions to the
7 appropriate places in Market Rule 1. The revisions also modify other relevant
8 provisions of Market Rule 1, including conforming the energy offer and
9 scheduling provisions in Section III.1 to the Forward Capacity Market design,
10 consolidating the Forward Capacity Market rights and obligations for Import
11 Capacity Resources in Section III.13.6, and relocating additional details of the
12 Forward Capacity Market capacity requirement calculation in Section III.13.7, to
13 remove references to the ICAP Transition Period and incorporate relevant ICAP
14 Transition Period concepts that must be utilized in the Forward Capacity Market.

15 **III. DESCRIPTION OF THE PROPOSED REVISIONS**

16
17 **Q:** *Please describe the proposed revisions.*

18 **A:** The revisions address the following, grouped generally into four categories:

19 **1. The ISO is proposing to replace ICAP Transition Period terminology**
20 **throughout Market Rule 1.** Throughout Market Rule 1 references to ICAP
21 Resources are being replaced with “resources with a Capacity Supply Obligation”
22 and similar terminology. Where appropriate, the reference is being broadened to
23 apply to both resources with a Capacity Supply Obligation and non-capacity
24 resources.

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2. The ISO is proposing to replace ICAP-specific requirements pertaining to energy offers, resource scheduling and other similar provisions in Sections III.1 through III.6 of Market Rule 1. Specifically:

- In Section III.1.7.20 on information and operating requirements for Market Participants selling energy into the New England Markets, the requirement that Market Participants report to the ISO sources of energy available for operation is being removed because this information is already provided as part of the Supply Offer, and the requirement applies to both capacity and non-capacity resources that are offering to sell energy into the New England Markets.
- Language in Sections III.1.10.1(c), III.10.3(d) and III.1.10.5(d) regarding obligations in the event of deviations between Day-Ahead and Real-Time energy purchases or sales is being conformed to remove slight variations in the manner in which the same obligation was expressed.
- The Day-Ahead Energy Market offer requirements and Self-Scheduling requirements in Sections III.1.10.1A(d) and (f) and III.1.10.3 are being revised to remove the requirements pertaining to ICAP Resources. For the Forward Capacity Market, these requirements are contained in the rights and obligations provisions in Section III.13.6. In addition, a cross-reference is being added in Section III.1.10.3 to clarify that there are additional offer-related obligations in Section III.13.6.2 for resources without a Capacity Supply Obligation.

- 1 • Section III.1.10.4 provisions regarding scheduling of ICAP Resources and
2 related obligations are being removed, as this section pertains specifically to
3 resource treatment and obligations during the ICAP Transition Period.
- 4 • Section III.1.11.4 regarding ISO actions in the event of an Emergency
5 Condition is being revised to remove the reference to ICAP Resources and to
6 clarify the language in this provision that explains the curtailment priority for
7 export transactions in the event the ISO anticipates or declares an Emergency
8 Condition. Specifically, in accordance with current practice, the language
9 clarifies that in the event the ISO anticipates or declares an Emergency
10 Condition, External Transaction sales out of New England that are not backed
11 by a resource may be interrupted in order to serve load and Operating Reserve
12 in New England.
- 13 • In Section III.6.4.4, sub-section (c) on the allocation of fixed cost charges
14 associated with Reliability Agreements negotiated under Appendix A of
15 Market Rule 1 is being removed for the commencement of the first Capacity
16 Commitment Period of the Forward Capacity Market. These provisions
17 sunset on June 1, 2010 per Market Rule 1, Section III.A, *Exhibit 2*, Section
18 2.4. The deletion of Section III.6.4.4(c) requires a coincident change to
19 III.11.1(c). The current Section III.11.1(c) specifies that the allocation of
20 GAP RFP costs are to be “allocated and charged in the same manner as fixed-
21 cost charges associated with Local Second Contingency Protection Resources
22 under Section III.6.4.4(c) of this Market Rule.” Since Section III.6.4.4(c) is

1 deleted as part of these instant changes, the language on cost allocation is
2 relocated from Section III.6.4.4(c) to Section III.11.1.(c).

3 **3. The ISO is proposing to remove or relocate (as applicable) the ICAP**
4 **Transition Period market rules in Section III.8 of Market Rule 1.**

5 **Specifically:**

- 6 • **Payments and Eligibility.** Provisions in Section III.8.1, III.8.2 and III.8.3
7 pertaining to the ICAP Payments and eligibility requirements for each
8 resource type to qualify for ICAP Payments during the ICAP Transition
9 Period are being removed. These provisions are superseded by the existing
10 provisions in Section III.13 of Market Rule 1 that address the qualification
11 requirements and rights and obligations of capacity resources in the Forward
12 Capacity Market and capacity payment provisions for the Forward Capacity
13 Market.
- 14 • **Treatment of Dispatchable Asset Related Demand.** Provisions in Section
15 III.8.1 and III.8.3.2 pertaining to the treatment of Dispatchable Asset Related
16 Demand during the ICAP Transition Period have been moved to a new
17 Section III.13.7.3.1.3 and a new Section III.1.10.6, respectively. The
18 provisions moved from Section III.8.1 to Section III.13.7.3.1.3 describe the
19 manner in which Market Participants are compensated for reductions in
20 consumption resulting from the performance of a Dispatchable Asset Related
21 Demand in the New England Markets. The provisions moved from Section
22 III.8.3.2 to Section III.1.10.6 detail the eligibility requirements with which a
23 Market Participant must comply to maintain a resource as a Dispatchable

1 Asset Related Demand in the New England Markets. Section III.1.10.6
2 contains a clarification to explain the manner in which a Market Participant
3 with a pumped storage generator that does not have a Capacity Supply
4 Obligation in the Forward Capacity Market can schedule the dispatchable
5 pumping demand of the generator should it wish to do so.

- 6 • **Other Demand Resources.** Section III.8.3.6.2 of Market Rule 1 contains the
7 ICAP Payment eligibility requirements for Other Demand Resource projects
8 during the ICAP Transition Period. Other Demand Resources include certain
9 merchant, utility or state-sponsored energy efficiency, load management and
10 distributed generation programs, and are currently described in more detail in
11 Section III.8.3.6.2.1. The Other Demand Resource concept is not a distinct
12 form of resource under the Forward Capacity Market construct. Instead, a
13 project that constitutes an Other Demand Resource in the ICAP Transition
14 Period is required to qualify for participation in a Forward Capacity Auction
15 under one of the four primary classifications of Demand Resources that is
16 recognized under the Forward Capacity Market, *i.e.*, On-Peak Demand
17 Resources, Seasonal Peak Demand Resources, Real-Time Demand Response
18 Resources, or Real-Time Emergency Generation Resources. Accordingly, the
19 Other Demand Resource concept is not being carried over into Section III.13
20 of Market Rule 1.

- 21 • **External Transactions.** Several changes pertaining to capacity imports are
22 being proposed in light of the differences in the treatment of these resources
23 during the ICAP Transition Period and for the Forward Capacity Market:

- 1 ○ Requirements pertaining to the curtailment priority of energy associated
2 with a capacity import resource that is backed by a Control Area has been
3 moved from Section III.8.3.7.2.1(d) to the New Capacity Import Resource
4 qualification provisions Section III.13.1.3.5.1. This provision requires that
5 a Market Participant qualifying a New Capacity Import Resource for a
6 Control Area-backed capacity resource provide documentation that the
7 energy associated with the imported capacity will be afforded the same
8 curtailment priority as that of the Control Area’s native load.
- 9 ○ Energy offer requirements for import resources are being carried over
10 from Section III.8.3.7.2.2 to the rights and obligations provisions for
11 Import Capacity Resources in the Forward Capacity Market in Sections
12 III.13.6.1.2.1 and III.13.6.1.2.2. These requirements pertain to the
13 submittal of matching External Transactions for energy in the Day-Ahead
14 Energy Market and Real-Time Energy Market, the timing of the submittal
15 of External Transactions, and special requirements that apply to Priced
16 External Transactions that are on an external interface for which advance
17 transmission reservations are required. Section III.1.10.7(e) is also being
18 modified to replace the provisions pertaining to the treatment of Priced
19 External Transactions on an external interface for which advance
20 transmission reservations are required with a cross reference to the
21 provision added to Section III.13.6.1.2.1.

- 22 ● **Remaining Section III.8 Provisions.** Requirements pertaining to the
23 scheduling of outages for capacity resources (Section III.8.4), the submission

1 of operating data (Section III.8.5), sanctioning for failing to satisfy offer and
2 other requirements for capacity resources (Section III.8.6), and the de-listing
3 of capacity resources and requirements for de-listed resources (Section III.8.7)
4 are all addressed, to the extent required under the Forward Capacity Market
5 construct, in Section III.13 and therefore are not being carried forward into
6 those market rules. The provisions in Section III.8.8 on the determination of
7 UCAP ratings for ICAP Resources are specific to the ICAP Transition Period
8 and are replaced for the Forward Capacity Market with rules in Section
9 III.13.1 for resources qualifying for a Forward Capacity Auction and in
10 Section III.13.7.1 on performance measures for capacity resources. The
11 majority of the provisions in Section III.8.9 on ICAP Payment cost allocation
12 are also specific to the ICAP Transition Period and are replaced for the
13 Forward Capacity Market with rules in Section III.13.7.3 on cost allocation
14 for Forward Capacity Market payments. Certain loads are assigned a peak
15 contribution of zero under both ICAP Transition Period and Forward Capacity
16 Market and these provisions are retained and relocated from III.8.9.2 to
17 III.13.7.3.1. The term UCAP Peak Contribution, which is utilized in Section
18 III.8.9 for cost allocation purposes, is being changed to “Coincident Peak
19 Contribution” and revised to incorporate the Section III.8.9 concept of “the
20 sum of the prior year’s annual coincident peak contributions of the customers
21 served by the Market Participant at each Load Asset in all Load Zones.” The
22 Coincident Peak Contribution value is also used in Section III.13.7.3 as part of
23 the charge adjustments mechanisms for Dispatchable Asset Related Demand.

1 **4. The ISO is proposing to add to the rules for calculating the Installed**
2 **Capacity Requirement a cross-reference to the applicable capacity resource**
3 **retirement provision.** Section III.12.6(a)(i) addresses the issue of which
4 generating units will be included in the modeling assumptions used in
5 determining the network model that is employed for purposes of calculating the
6 Installed Capacity Requirement. This Section is being revised to reflect that,
7 under the Forward Capacity Market design, capacity resource retirement
8 determinations are made in accordance with the Forward Capacity Market
9 retirement provisions in Section III.13.2.5.2.5.3 rather than the general generating
10 resource retirement provisions in Section I.3.9 and Section II.47 of the ISO Tariff.
11 The current version of Section I.3.9 makes clear that Section III.13.2.5.2.5.3
12 governs retirement determinations for capacity resources.

13 **IV. CONCLUSION**

14 ***Q: Please explain why the ISO is proposing these changes.***

15 **A:** With the completion of the ICAP Transition Period and commencement of the
16 first Forward Capacity Market Capacity Commitment Period on June 1, 2010, it is
17 important that market rules pertaining to installed capacity during the ICAP
18 Transition Period either be removed, revised or relocated to indicate how those
19 requirements apply under the Forward Capacity Market construct. The changes
20 proposed by the ISO in this filing accomplish these objectives, and therefore are
21 necessary and important changes that support the ISO's administration of the New
22 England Markets.

1 Q: *Does this conclude your testimony?*

2 A: Yes.

3

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

5 Executed on: 3/31/10

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Janine Dombrowski

Attachment 4

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